Rebecca J. Dulin
Senior Counsel

Duke Energy
1201 Main Street
Capital Center Building
Suite 1180
Columbia, SC 29201

o: 803.988.7130
f: 803.988.7123
Rebecca.Dulin@duke-energy.com

October 14, 2016

VIA ELECTRONIC FILING

The Honorable Jocelyn G. Boyd
Chief Clerk/Administrator
Public Service Commission of South Carolina
101 Executive Center Drive, Suite 100
Columbia, South Carolina 29210

Re: **2016 Duke Energy Carolinas Integrated Resource Plan Supplemental Filing Docket No. 2016-10-E**

Dear Mrs. Boyd:

On September 1, 2016, Duke Energy Carolinas, LLC ("DEC" or the "Company") filed with this Commission its 2016 Integrated Resource Plan ("2016 DEC IRP"). Upon internal review, DEC became aware of several non-substantive errors in its IRP that it is correcting through this filing. The corrections are summarized below:

- Page 1: Changes to title
- Page 13: Add natural gas boiler to list of generation assets
- Page 29 (and Page 141): Add landfill gas to the list of dispatchable technologies that were evaluated
- Page 42: Correct nuclear uprate from 91 MW to 85 MW
- Page 50, Table 8-H: Correct CT total from 700 MW to 468 MW
- Page 51, Table 8-I[1]: Move New CT from 2027 to 2026
- Pages 57-58[2]: Correct information on North Carolina RFP compliance
- Page 72, Table A-2[3]: Add additional descriptive language
- Page 73[4]: Correct reference from Portfolio #4 to Portfolio #1
- Page 126[5]: Correct year reference from 2033 to 2031
- Page 139[6]: Correct typographical error

[1] Listed as page 52 on red-lined version due to formatting changes when including revisions.
[2] Listed as pages 59-60 on red-lined version.
[3] Listed as page 74 on red-lined version.
[4] Listed as page 75 on red-lined version.
[5] Listed as page 128 on red-lined version.
[6] Listed as page 141 on red-lined version.

- Page 141[7]: Move reference to battery from Non-Dispatchable to Dispatchable
- Page 159, Table H-2[8]: Corrections to Confidential Version

Enclosed for electronic filing is a corrected copy of the Public Version of the 2016 DEC IRP, along with a red-lined version of the revised pages of the Public Version showing where the corrections have been made, with the exception of Page 159, which is confidential in nature.

In addition, we are hand delivering to the Commission and the Office of Regulatory Staff copies of the corrected Public and Confidential Versions and a red-lined version of the revised pages of the Public Version and the Confidential Version. Consistent with the initial filing of the 2016 DEC IRP, the Company is filing the corrected Confidential Version and the red-lined version the Confidential Version under seal and requests the Commission extend by reference the confidential treatment of the September 1, 2016 filing granted in Order No. 2016-656 to this supplemental filing.

Should you have any questions regarding this matter, please do not hesitate to contact me at 803.988.7130.

Sincerely,

Rebecca J. Dulin

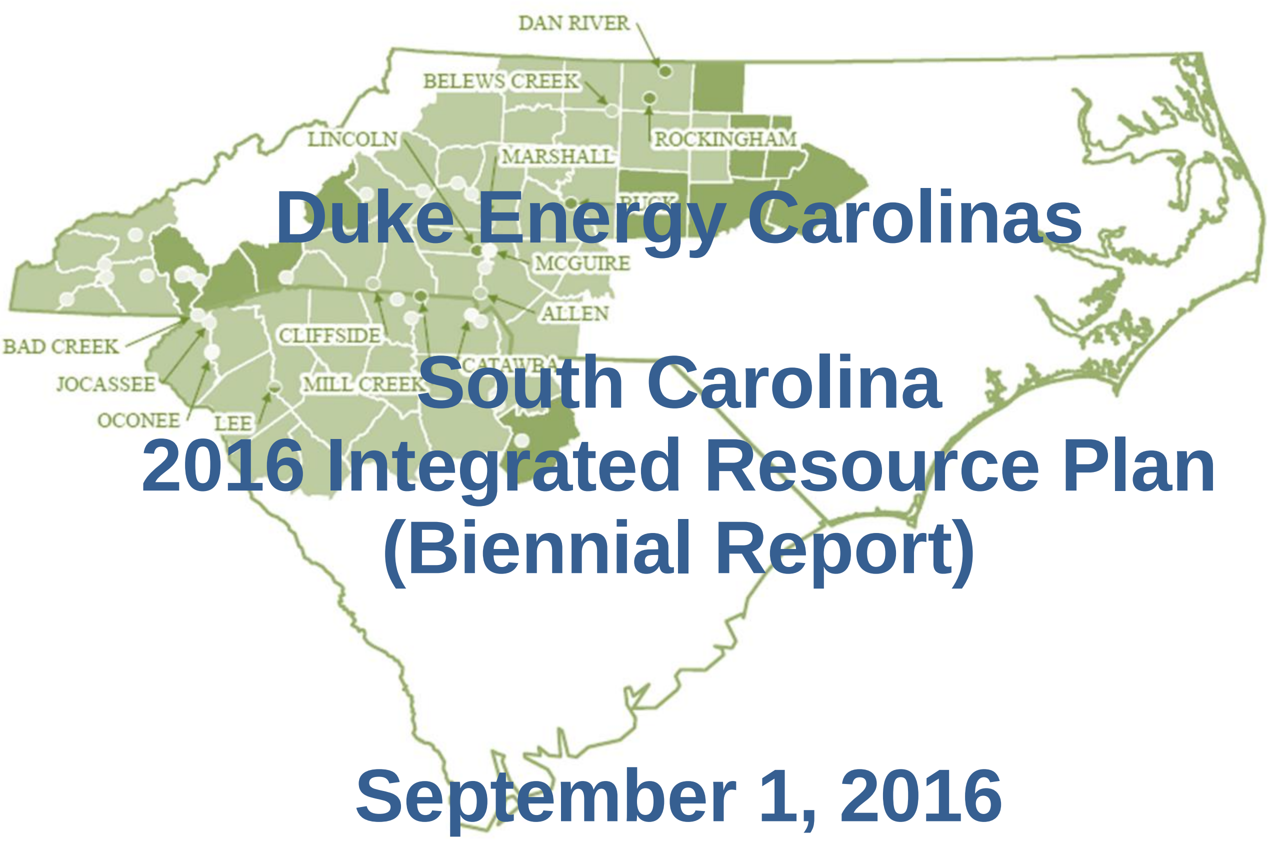
Rebecca J. Dulin

Enclosure

cc: Dawn Hipp, ORS – Director of Utilities, Safety & Transportation
Nanette S. Edwards, ORS - Deputy Executive Director
Jeffrey M. Nelson, ORS - Chief Counsel & Director of Legal Services
Shannon Bowyer Hudson, ORS - Deputy Director of Legal Services
J. Blanding Holman, IV, Counsel, Southern Environmental Law Center
Frank R. Ellerbe, III, Robinson, McFadden & Moore, P.C.
Heather S. Smith, Deputy General Counsel, Duke Energy Carolinas, LLC

[7] Listed as page 143 on red-lined version.
[8] Listed as page 161 on CONFIDENTIAL red-lined version.

DUKE ENERGY
CAROLINAS



Duke Energy Carolinas

South Carolina
2016 Integrated Resource Plan
(Biennial Report)

September 1, 2016

PUBLIC

DEC 2016 IRP TABLE OF CONTENTS

ABBREVIATIONS	
BCFD	Billion Cubic Feet Per Day
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CAPP	Central Appalachian Coal
CC	Combined Cycle
CCR	Coal Combustion Residuals
CECPCN	Certificate of Environmental Compatibility and Public Convenience and Necessity
CFL	Compact Fluorescent Light bulbs
CO_2	Carbon Dioxide
COD	Commercial Operation Date
COL	Combined Construction and Operating License
COWICS	Carolinas Offshore Wind Integration Case Study
CPCN	Certificate of Public Convenience and Necessity
CSAPR	Cross State Air Pollution Rule
CT	Combustion Turbine
DC	Direct Current
DEC	Duke Energy Carolinas
DEP	Duke Energy Progress
DOE	Department of Energy
DSM	Demand Side Management
EE	Energy Efficiency Programs
EIA	Energy Information Administration
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
FERC	Federal Energy Regulatory Commission
FGD	Flue Gas Desulfurization
FLG	Federal Loan Guarantee
FPS	Feet Per Second
GHG	Greenhouse Gas
HVAC	Heating, Ventilation and Air Conditioning
IGCC	Integrated Gasification Combined Cycle
IRP	Integrated Resource Plan
IS	Interruptible Service
JDA	Joint Dispatch Agreement
LCR Table	Load, Capacity, and Reserve Margin Table
LEED	Leadership in Energy and Environmental Design
MACT	Maximum Achievable Control Technology
MATS	Mercury Air Toxics Standard
MGD	Million Gallons Per Day
NAAQS	National Ambient Air Quality Standards
NAP	Northern Appalachian Coal
NC	North Carolina
NCCSA	North Carolina Clean Smokestacks Act
NCDAQ	North Carolina Division of Air Quality
NCEMC	North Carolina Electric Membership Corporation
NCMPA1	North Carolina Municipal Power Agency #1
NCTPC	NC Transmission Planning Collaborative
NCUC	North Carolina Utilities Commission

ABBREVIATIONS CONT.	
NERC	North American Electric Reliability Corp
NO_x	Nitrogen Oxide
NPDES	National Pollutant Discharge Elimination System
NRC	Nuclear Regulatory Commission
NSPS	New Source Performance Standard
OATT	Open Access Transmission Tariff
PD	Power Delivery
PEV	Plug-In Electric Vehicles
PMPA	Piedmont Municipal Power Agency
PPA	Purchase Power Agreement
PPB	Parts Per Billion
PSCSC	Public Service Commission of South Carolina
PSD	Prevention of Significant Deterioration
PV	Photovoltaic
PVDG	Solar Photovoltaic Distributed Generation Program
PVRR	Present Value Revenue Requirements
QF	Qualifying Facility
RCRA	Resource Conservation Recovery Act
REC	Renewable Energy Certificates
REPS	Renewable Energy and Energy Efficiency Portfolio Standard
RFP	Request for Proposal
RIM	Rate Impact Measure
RPS	Renewable Portfolio Standard
SC	South Carolina
SCR	Selective Catalytic Reduction
SEPA	Southeastern Power Administration
SERC	SERC Reliability Corporation
SG	Standby Generation
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
TAG	Technology Assessment Guide
TRC	Total Resource Cost
The Company	Duke Energy Carolinas
The Plan	Duke Energy Carolinas Annual Plan
UG/M^3	Micrograms Per Cubic Meter
UCT	Utility Cost Test
VACAR	Virginia/Carolinas
VAR	Volt Ampere Reactive

1. EXECUTIVE SUMMARY

Overview

For more than a century, Duke Energy Carolinas (DEC) has provided affordable and reliable electricity to customers in North Carolina (NC) and South Carolina (SC) now totaling more than 2.4 million in number. Each year, as required by the North Carolina Utilities Commission (NCUC) and the Public Service Commission of South Carolina (PSCSC), DEC submits a long-range planning document called the Integrated Resource Plan (IRP) detailing potential infrastructure needed to meet the forecasted electricity requirements for our customers over the next 15 years.

The 2016 IRP is the best projection of how the Company's energy portfolio will look over the next 15 years, based on current data assumptions. This projection may change over time as variables such as the projected load forecasts, fuel price forecasts, environmental regulations, technology performance characteristics and other outside factors change.

The proposed plan will meet the following objectives:

- Provide reliable electricity especially during peak demand periods by maintaining adequate reserve margins. Peak demand refers to the highest amount of electricity being consumed for any given hour across DEC's entire system.
- Add new resources at the lowest reasonable cost to customers. These resources include a balance of energy efficiency (EE) programs, demand-side management programs (DSM), renewable resources, nuclear facilities, hydro generation and natural gas generation.
- Improve the environmental footprint of the portfolio by meeting or exceeding all federal, state and local environmental regulations.

A New Era – Plans to Specifically Include Consideration of Winter Demand for Power

Historically, DEC's resource plans have projected the need for new resources based primarily on the need to meet summer afternoon peak demand projections. For the first time in the 2016 IRP, DEC is now developing resource plans that also include new resource additions driven by winter peak demand projections inclusive of winter reserve requirements. The completion of a comprehensive reliability study demonstrated the need to include winter peak planning in the IRP process. The study recognized the growing volatility associated with winter morning peak demand conditions such as those observed during recent polar vortex events. The study also incorporated the expected growth in "summer-oriented resources" such as solar facilities and air conditioning load control programs that provide valuable assistance in meeting summer afternoon peak demands on the system but do little to assist in meeting demand for power on cold winter mornings. As a result of the reliability study, DEC has now added a winter planning reserve target of 17% to its 2016 IRP.

The Road Ahead— Determining Customer Electricity Needs 2017 – 2031

The 2016 IRP identifies the incremental amount of electricity our customers will require over the next 15 years using the following basic formula:

Growth in Peak Demand and Energy Consumption	+	Resource Retirements	=	New Resource Needs

The annual energy consumption growth rate for all customers is forecasted to be 1.1%. This growth rate is offset by projections for utility-sponsored EE impacts, reducing the projected growth rate by 0.1% for a net growth rate of 1.0% after accounting for energy efficiency. Peak demand growth net of EE is expected to grow slightly faster than overall energy consumption with an average projected growth rate of 1.3% (winter).

Peak demand refers to the highest hourly level of energy consumption, given expected weather, throughout the year. The Company also carries reserve capacity to provide reliable supply during extreme weather conditions.

Projected electricity consumption growth rates net of EE by customer class are as follows:

- Commercial class, mainly driven by offices, education and retail, is the fastest growing class with a projected growth rate of 1.3%.
- Industrial class has a projected growth rate of 0.9%.
- Residential class has a projected growth rate of 1.2%.

In addition to customer growth, plant retirements and expiring purchase power contracts create the need to add incremental resources to allow the Company to reliably meet future customer demand. Over the last several years, aging, less efficient coal power plants have been replaced with a combination of renewable energy, EE, DSM, hydro generation and state-of-the art natural gas generation facilities.

The Company recently closed its last coal facility not equipped with advanced emission controls. In April 2015, Lee Steam Station Units 1 and 2 in Anderson County, SC were shuttered. Unit 3 was converted into a natural gas-fired unit. These closings are the most recent in a series of coal unit retirements totaling approximately 1,700 megawatts (MW) (winter/summer) of cumulative retirements. Additionally, the Company plans to retire the 1,161 MW/1,127 MW (winter/summer) Allen Steam Station with Units 1-3 scheduled to retire by December 2024 and Units 4 and 5 in 2028. Finally, DEC has retired approximately 400 MW (summer/winter) of older combustion turbine (CT) units.

The ultimate timing of unit retirements can be influenced by factors that impact the economics of continued unit operations. Such factors include changes in relative fuel prices, operations and maintenance costs and the costs associated with compliance of evolving environmental regulations. As such, unit retirement schedules are expected to change over time as market conditions change.

Strategy to Meet Customer Needs

Natural Gas

Currently, natural gas resources such as combined cycles (CC) and combustion turbines only make up 20% of the winter generating capacity in DEC. The 2016 IRP identifies the need for additional natural gas resources that are economic, highly efficient and reliable. The planning document outlines the following relative to new natural gas resources. Locations for most of these facilities have not been finalized:

- Complete construction of the 683 MW/653 MW (winter/summer) natural gas combined cycle plant at Lee Steam Station, Anderson County, SC, (Lee CC) expected to be commercially available by the end of 2017. An additional 100 MW of capacity will be purchased by North Carolina Electric Membership Corporation (NCEMC).
- Plan for a 1,221 MW/1,123 MW (winter/summer) natural gas combined cycle in 2023.
- Plan for 468 MW/435 MW (winter/summer) of combustion turbine resources in 2025.

Nuclear Power

The Company expects to receive the Combined Construction and Operating License (COL) for the W.S. Lee Nuclear Station (Lee Nuclear) by the end of 2016. The 2016 IRP continues to support new nuclear generation as a carbon-free, cost-effective, reliable option within the Company's resource portfolio. Historically low natural gas prices, ambiguity regarding the timing and impact of environmental regulations and uncertainty regarding the potential to extend the licenses of existing nuclear units affects the timing of the need for new nuclear generation. The

Company views all of its nuclear plants as excellent candidates for license extensions, however to date no nuclear plant licenses have been extended to operate from 60 years to 80 years. As such, there is uncertainty regarding the ability to receive a license extension, as well as, any costs that may be required to operate an additional 20 years. Given the uncertainty of license extension, the IRP Base Case does not assume license extension at this time, but rather considers relicensing as a sensitivity to the Base Case.

Additionally, final resolution of environmental regulations, such as the Environmental Protection Agency's (EPA's) Clean Power Plan (CPP), will significantly impact the Company's generation portfolio. In light of this uncertainty and the historic volatility of natural gas prices, the Company evaluated its resource needs, including new nuclear generation, over a range of reasonable scenarios. The results of this evaluation demonstrated the need for new nuclear generation across the scenarios, though the timing of the need varied from the mid- 2020s to the early 2030s depending upon the assumptions. The Company believes these results demonstrate the value of obtaining the COL for the W.S. Lee Nuclear Station (Lee Nuclear) to the portfolio and customers.

The base planning case in this IRP models commercial operation of the Lee nuclear units in 2026 and 2028. The uncertainties described above may result in a potential accelerated need for Lee Nuclear when compared to the base planning case. The COL application anticipates the need for Lee Nuclear as early as 2024 and 2026 and those dates are reflected in the license application.

The current IRP base plan identifies the following:

- Commercial operation of the first unit at the Lee Nuclear Station by November 2026.
- Review the potential need for additional new nuclear capacity so that it is available in advance of the Oconee license expiration.
- Study the possibility of a license extension from the current 60 years to 80 years at the Oconee Nuclear Station extending its operations until the 2053-2054 time frame.

Renewable Energy and Solar Resources

Renewable mandates, substantial tax subsidies and declining costs make solar energy the Company's primary renewable energy resource in the 2016 IRP. DEC continues to add solar energy to its resource mix through Purchased Power Agreements (PPAs), Renewable Energy Credit (REC) purchases and utility-owned solar generation. The 2016 IRP projects:

- Increasing all solar energy resources from 735 MW in 2017 to 2,168 MW (nameplate) in 2031.
- Complying with NC Renewable Energy and Energy Efficiency Portfolio Standards (NC REPS or REPS) through a combination of solar, other renewables, EE and REC purchases.
- Meeting increasing goals of the South Carolina Distributed Energy Resource Program (SC DER) through 2020.
- Meeting growing customer demand for renewable resources outside of mandated compliance programs.

While the Company is aggressively pursuing solar as a renewable resource, the 2016 IRP recognizes and plans for its operational limitations. Solar energy is an intermittent renewable energy source that cannot be dispatched to meet changing customer demand during all hours of the day and night or through all types of weather. Solar has limited ability to meet peak demand conditions that occur during early morning winter hours or summer evening hours. As such, solar energy must be combined with resources such as EE, DSM, natural gas, hydro and nuclear generation to make up the Company's diverse resource portfolio to ensure system reliability.

Energy Efficiency and Demand-Side Management

Existing programs along with new EE and DSM programs approved since the last biennial IRP in 2014 are supporting efforts to reduce the annual forecasted demand growth over the next 15 years. Aggressive marketing campaigns have been launched to make customers aware of DEC's extensive EE and DSM program offerings, successfully increasing customer adoption. The Company is forecasting continued energy and capacity savings from both EE and DSM programs through the planning period as depicted in the table below.

Table Exec-1: DEC Projected EE and DSM Energy and Capacity Savings (Winter)

Projected EE and DSM Energy and Capacity Savings		
Year	**Energy (MWh)**	**Capacity (MW)**
2017	600,000	547
2031	3,564,500	1,130

Cost-effective EE and DSM programs can help delay the Company's need to construct and operate new generation. The Base Case includes the current projections for cost-effective achievable savings. Even greater savings may be possible depending on variables such as customer participation and future technology innovations. Alternative resource portfolios with these higher levels are presented in Appendix A.

Existing Resources and Alternative Generation

DEC continues to look for opportunities to make enhancements to its existing resources. As such, the Company expects to complete uprates to each unit of its Bad Creek pumped storage facility in the 2020 – 2023 timeframe. Each uprate is expected to provide an additional 46 MW to each unit. These uprates will not only provide valuable capacity to the DEC system, but will also be an important asset for providing support to the transmission system as intermittent sources of energy, such as solar, continue to grow in the Carolinas.

DEC continues to explore alternative generation types for feasibility and economic viability to potentially meet future customer demand. As these generation types become viable and economically feasible, the Company will consider them in the planning process. In the 2016 IRP, capacity from Combined Heat and Power (CHP) projects have been increased in the resource plan. CHP projects efficiently provide both power to the grid while simultaneously meeting the steam requirements of large institutions and industries in the Carolinas. The current CHP projection for DEC is 109 MW/100 MW (winter/summer) of CHP in the 2018 – 2021 timeframe.

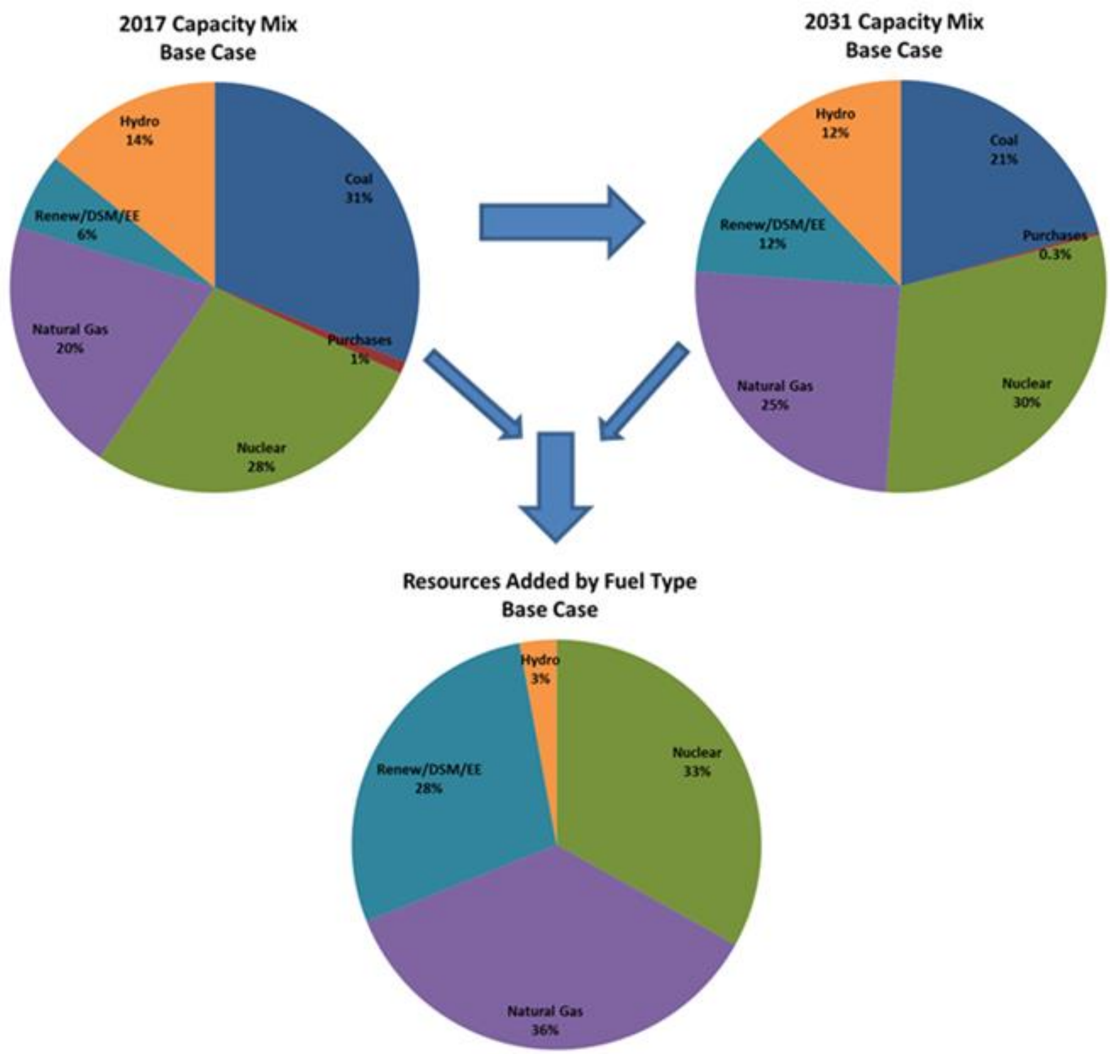
Strong Trend Toward Cleaner, More Environmentally Friendly Generation

When viewed in total, more than 54% of DEC and DEP's collective energy needs in 2017 are met by emission-free resources. This includes nuclear energy, hydro-electric power, DSM, EE and renewable energy. The remaining 46% of the energy portfolio includes clean, efficient natural gas units and coal plants that are equipped with state-of-the-art emission technology. Based upon the EPA carbon standards for new generation, the 2016 IRP does not call for the construction of any new coal plants.

The EPA's Clean Power Plan continues to influence the development of the Company's resource plans. While the CPP was stayed by the U.S. Supreme Court in 2016, the Company continues to plan for a range of carbon dioxide (CO_2) legislative outcomes. As such, DEC's base resource plan assumes some level of carbon emission restrictions consistent with the CPP, while alternate views of CO_2 legislative outcomes were considered as sensitivities.

The figure below illustrates how the Company's winter capacity mix is expected to change over the planning horizon. As shown in the bottom pie chart, DSM, EE and renewables will combine to represent approximately one-third of the Company's new installed capacity over the study period. The plan also calls for approximately 36% of future new capacity to come from new natural gas generation with the final 33% coming from nuclear generation. In aggregate, the incremental resource additions identified in the 2016 IRP contribute to an economic, reliable and increasingly clean energy portfolio for the citizens of North Carolina and South Carolina.

Figure Exec-1: 2017 and 2031 Capacity Mix and Sources of Incremental Capacity Additions



Note: Capacity based on winter ratings (renewables based on nameplate)

This report is intended to provide stakeholders insight into the Company's planning process for meeting forecasted customer peak demand and cumulative energy needs over the 15-year planning horizon. Such stakeholders include: legislative policymakers, public utility commissioners and their staffs, residential, commercial and industrial retail customers, wholesale customers, environmental advocates, renewable resource industry groups and the general public. A more detailed presentation of the Base Case, as described in the above Executive Summary, is included in this document in Chapter 8 and Appendix A.

The following chapters of this document provide an overview of the inputs, analysis and results included in the 2016 IRP. In addition to the Base Case, five different resource portfolios were analyzed under multiple sensitivities. Finally, the appendices to the document give even greater detail and specific information regarding the input development and the analytic process utilized in the 2016 IRP.

2. SYSTEM OVERVIEW

DEC provides electric service to an approximately 24,088-square-mile service area in central and western North Carolina and western South Carolina. In addition to retail sales to approximately 2.48 million customers, the Company also sells wholesale electricity to incorporated municipalities and to public and private utilities. Recent historical values for the number of customers and sales of electricity by customer groupings may be found in Appendix C.

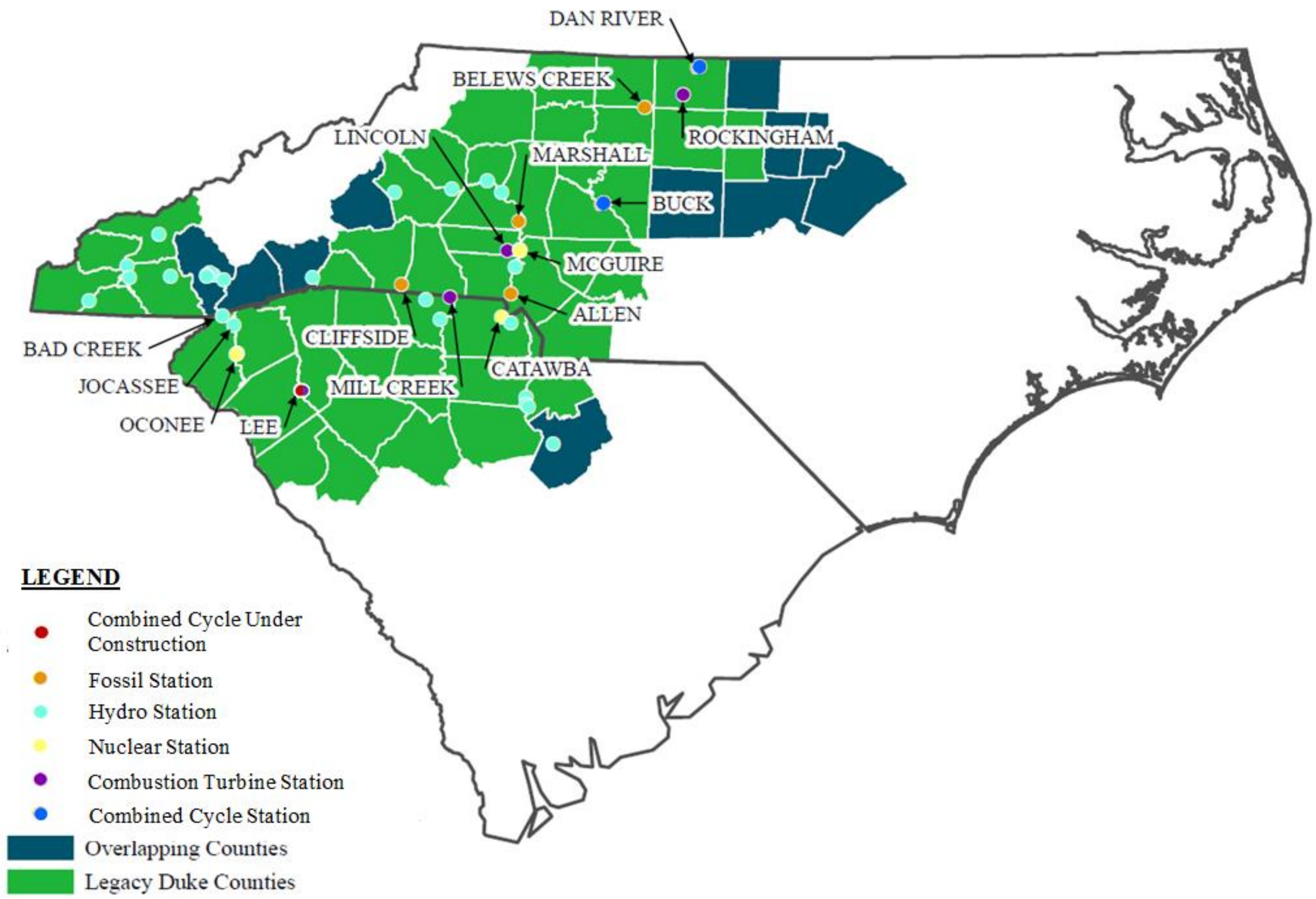
DEC currently meets energy demand, in part, by purchases from the open market, through longer-term purchased power contracts and from the following electric generation assets:

- Three nuclear generating stations with a combined capacity of 7,358 MW/7,160 MW (winter/summer)
- Four coal-fired stations with a combined capacity of 6,859 MW/ 6,821 MW (winter/summer)
- 29 hydroelectric stations (including two pumped-storage facilities) with a combined capacity of 3,238 MW (winter/summer)
- Four CT stations and two CC stations with a combined capacity of 4,607 MW/4,089 MW (winter/summer)
- 18 utility-owned solar facilities with a combined firm capacity of 3.9 MW
- One natural gas boiler with a capacity of 170 MW (winter/summer)

The Company's power delivery system consists of approximately 103,140 miles of distribution lines and 13,087 miles of transmission lines. The transmission system is directly connected to all of the Transmission Operators that surround the DEC service territory. There are 36 tie-line circuits connecting with nine different Transmission Operators: DEP, PJM Interconnection, LLC (PJM), Tennessee Valley Authority (TVA), Smokey Mountain Transmission, Southern Company, Yadkin, Southeastern Power Administration (SEPA), South Carolina Electric & Gas (SCE&G) and Santee Cooper. These interconnections allow utilities to work together to provide an additional level of reliability. The strength of the system is also reinforced through coordination with other electric service providers in the Virginia-Carolinas (VACAR) sub-region, SERC Reliability Corporation (SERC) (formerly Southeastern Electric Reliability Council) and North American Electric Reliability Corporation (NERC).

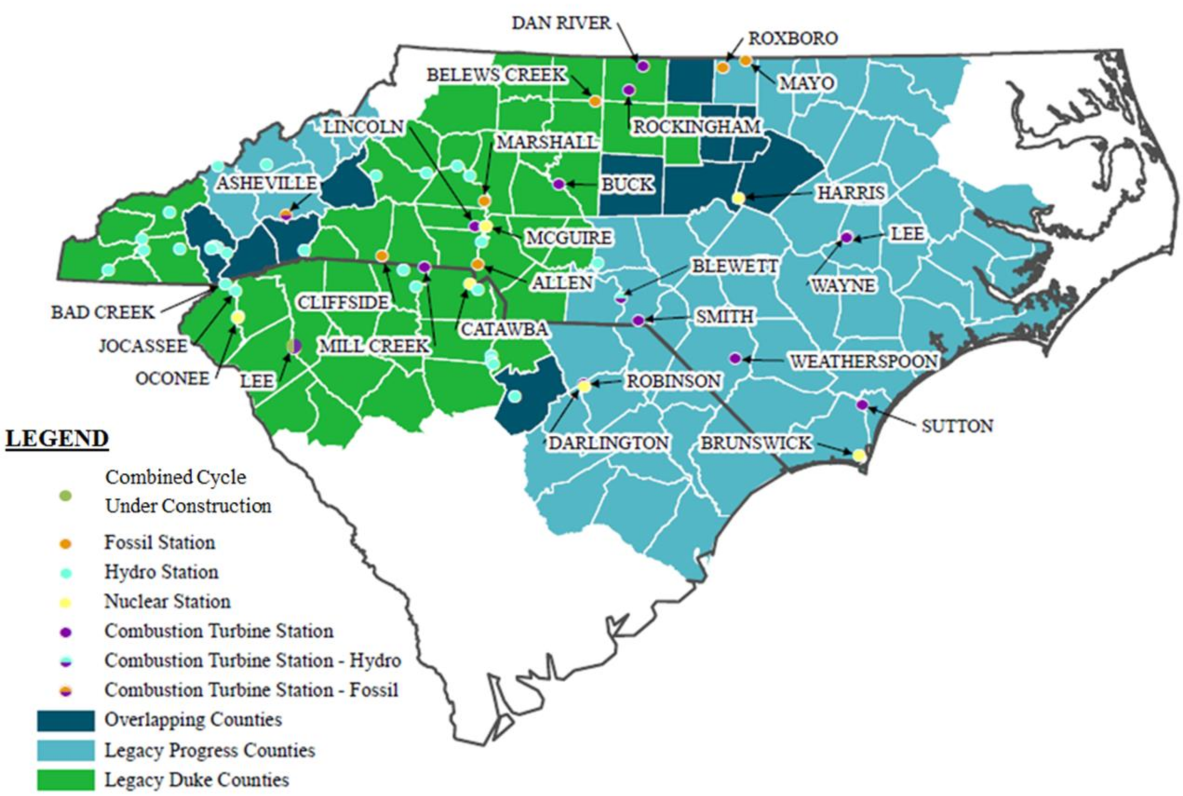
The map on the following page provides a high-level view of the DEC service area.

Chart 2-A Duke Energy Carolinas Service Area



With the closing of the Duke Energy Corporation and Progress Energy Corporation merger, the service territories for both DEC and DEP lend to future opportunities for collaboration and potential sharing of capacity to create additional savings for North Carolina and South Carolina customers of both utilities. An illustration of the service territories of the Companies are shown in the map below.

Chart 2-B DEC and DEP Service Area



3. ELECTRIC LOAD FORECAST

The Duke Energy Carolinas' Spring 2016 Forecast provides projections of the energy and peak demand needs for its service area. The forecast covers the time period of 2017 – 2031 and represents the needs of the Retail customers and Wholesale customers.

Energy projections are developed with econometric models using key economic factors such as income, electricity prices, industrial production indices, along with weather, appliance efficiency trends, rooftop solar trends, and electric vehicle trends. Population is also used in the Residential customer model. DEC has used regression analysis since 1979 and this technique has yielded consistently reasonable results over the years.

The economic projections used in the Spring 2016 Forecast are obtained from Moody's Analytics, a nationally recognized economic forecasting firm, and include economic forecasts for the states of North Carolina and South Carolina.

The Retail forecast consists of the three major classes: Residential, Commercial and Industrial.

The Residential class sales forecast is comprised of two projections. The first is the number of residential customers, which is driven by population. The second is energy usage per customer, which is driven by weather, regional economic and demographic trends, electric price and appliance efficiencies.

The usage per customer forecast was derived using a Statistical Adjusted End-Use Model (SAE). This is a regression-based framework that uses projected appliance saturation and efficiency trends developed by Itron using Energy Information Administration (EIA) data. It incorporates naturally occurring efficiency trends and government mandates more explicitly than other models. The outlook for usage per customer is slightly negative to flat through much of the forecast horizon, so most of the growth is primarily due to customer increases. The projected energy growth rate of Residential in the Spring 2016 Forecast after all adjustments for Utility Energy Efficiency (UEE) programs, Solar and Electric Vehicles from 2017-2031 is 1.2%.

The Commercial forecast also uses an SAE model in an effort to reflect naturally occurring, as well as government mandated efficiency changes. The three largest sectors in the Commercial class are Offices, Education and Retail. Commercial is expected to be the fastest growing class, with a projected energy growth rate of 1.3%, after all adjustments.

The Industrial class is forecasted by a standard econometric model with drivers such as total manufacturing output, textile output, and the price of electricity. Overall, Industrial energy sales are expected to grow 0.9% over the forecast horizon, after all adjustments.

Peak Demand and Energy Forecast

If the impacts of new Duke Energy Carolinas UEE[1] programs are included, the projected compound annual growth rate for the summer peak demand is 1.2%, while winter peaks are forecasted to grow at a rate of 1.3%. The forecasted compound annual growth rate for annual energy consumption is 1.0% after the impacts of UEE programs are subtracted.

The Spring 2016 Forecast is lower than the Spring 2015 Forecast, with a growth in the summer peak of 1.4% in the 2015 forecast versus 1.2% in the new forecast. The Spring 2016 Forecast is lower due to a large Industrial plant closing, strong UEE accomplishments in recent years, and stronger projected Commercial heating and cooling efficiencies. The load forecast projection for energy and capacity including the impacts of EE that was utilized in the 2016 IRP is shown in Table 3-A.

Table 3-A Load Forecast with Energy Efficiency Programs

YEAR	SUMMER (MW)	WINTER (MW)	ENERGY (GWh)
2017	18,729	18,416	97,470
2018	18,948	18,665	98,345
2019	18,916	18,721	98,131
2020	19,127	18,957	99,132
2021	19,362	19,259	99,973
2022	19,562	19,466	100,630
2023	19,804	19,731	101,676
2024	20,046	20,011	102,902
2025	20,321	20,223	103,890
2026	20,581	20,570	105,078
2027	20,842	20,844	106,255
2028	21,146	21,161	107,646
2029	21,427	21,478	108,794
2030	21,723	21,734	110,074
2031	22,028	22,068	111,407

Note: Tables 8-B and 8-C differ from these values due to a 47 MW Piedmont Municipal Power Agency (PMPA) backstand contract through 2020.

A detailed discussion of the electric load forecast is provided in Appendix C.

[1] The term UEE is utilized in the load forecasting sections which represents utility-sponsored EE impacts net of free riders. The term "Gross EE" represents UEE plus naturally occurring energy efficiency in the marketplace.

4. ENERGY EFFICIENCY AND DEMAND SIDE MANAGEMENT

DEC is committed to making sure electricity remains available, reliable and affordable and that it is produced in an environmentally sound manner and, therefore, DEC advocates a balanced solution to meeting future energy needs in the Carolinas. That balance includes a strong commitment to energy efficiency and demand side management.

Since 2009, DEC has been actively developing and implementing new EE and DSM programs throughout its North Carolina and South Carolina service areas to help customers reduce their electricity demands. DEC's EE and DSM plan is designed to be flexible, with programs being evaluated on an ongoing basis so that program refinements and budget adjustments can be made in a timely fashion to maximize benefits and cost-effectiveness. Initiatives are aimed at helping all customer classes and market segments use energy more wisely. The potential for new technologies and new delivery options is also reviewed on an ongoing basis in order to provide customers with access to a comprehensive and current portfolio of programs.

DEC's EE programs encourage customers to save electricity by installing high efficiency measures and/or changing the way they use their existing electrical equipment. DEC evaluates the cost-effectiveness of EE/DSM programs from the perspective of program participants, non-participants, all customers as a whole and total utility spending using the four California Standard Practice tests (i.e., Participant Test, Rate Impact Measure (RIM) Test, Total Resource Cost (TRC) Test and Utility Cost Test (UCT), respectively) to ensure the programs can be provided at a lower cost than building supply-side alternatives. The use of multiple tests can ensure the development of a reasonable set of programs and indicate the likelihood that customers will participate. DEC will continue to seek approval from State utility commissions to implement EE and DSM programs that are cost-effective and consistent with DEC's forecasted resource needs over the planning horizon. DEC currently has approval from the NCUC and PSCSC to offer a large variety of EE and DSM programs and measures to help reduce electricity consumption across all types of customers and end-uses.

For IRP purposes, these EE-based demand and energy savings are treated as a reduction to the load forecast, which also serves to reduce the associated need to build new supply-side generation, transmission and distribution facilities. DEC also offers a variety of DSM (or demand response) programs that signal customers to reduce electricity use during select peak hours as specified by the Company. The IRP treats these "dispatchable" types of programs as resource options that can be dispatched to meet system capacity needs during periods of peak demand.

In 2011, DEC commissioned an EE market potential study to obtain estimates of the technical, economic and achievable potential for EE savings within the DEC service area. The final report was prepared by Forefront Economics Inc. and H. Gil Peach and Associates, LLC and was completed on February 23, 2012. The results of the market potential study are suitable for integrated resource planning purposes and use in long-range system planning models. However, the study did not attempt to closely forecast short-term EE achievements from year to year. Therefore, the Base Case EE/DSM savings contained in this IRP were projected by blending DEC's five-year program planning forecast into the long-term achievable potential projections from the market potential study. An updated Market Potential Study is currently underway and the results of that study should be available in time for the next DEC IRP process.

DEC prepared a Base Portfolio savings projection that was based on DEC's five year program plan for 2016-2020. For periods beyond 2020, the Base Portfolio assumed that the annual savings projected for 2020 would continue to be achieved in each year thereafter until such time as the total cumulative EE projections reached approximately 60% of the Economic Potential as estimated by the Market Potential Study described above. Beyond reaching 60% of the Economic Potential, sufficient EE savings would be added to keep up with growth in the customer load.

DEC also prepared a High Portfolio EE savings projection that assumed that the same types of programs in the Base Portfolio, including potential new technologies, can be offered at higher levels of participation provided that additional money is spent on program costs to encourage additional customers to participate.

Additionally, for both the Base and High Portfolios described above, DEC included an assumption that, when the EE measures included in the forecast reach the end of their useful lives, the impacts associated with these measures are removed from the future projected EE impacts. This concept of "rolling off" the impacts from EE programs is explained further in Appendix C.

See Appendix D for further detail on DEC's EE, DSM and consumer education programs, which also includes a discussion of the methodology for determining the cost effectiveness of EE and DSM programs. Grid modernization demand response impacts are also discussed in Appendix D.

5. RENEWABLE ENERGY STRATEGY / FORECAST

Since the last IRP was filed, the growth of renewable generation in the US continues to outpace that of non-renewable generation. In 2015, over 13,000 MW of wind and solar capacity were installed nationwide compared to 6,500 MW for natural gas, coal, nuclear, and other technologies. Most of the renewable growth is occurring in states with higher than average retail rates, renewable state mandates like NC REPS and/or tax incentives. Additionally, the requirements of the Public Utilities Regulatory Policy Act (PURPA) have driven renewable generation growth, especially in states with higher avoided cost rates and/or contract terms that are favorable to Qualifying Facilities (QFs). North Carolina has experienced this growth firsthand. The state ranked in the top 3 in the country in universal solar installations (>1MW in size) during the last two years, with the majority of that generating capacity owned by non-utility third parties.

Renewable mandates, substantial federal and state tax subsidies, and declining installed costs make solar capacity the Company's primary renewable energy resource in the 2016 IRP. The 2016 IRP makes the following key assumptions regarding renewable energy:

- Solar capacity increases from 735 MW in 2017 to 2,168 MW in 2031[2] (Base Case);
- Compliance with the NC REPS continues to be met through a combination of solar, other renewables, EE, and REC purchases;
- Achievement of the South Carolina Distributed Energy Resource Program goal of 120 MW of solar capacity located in DEC-South Carolina (DEC-SC);
- With no change in policy, and even with the expiration of the NC state tax incentive in 2015, additional renewable capacity, particularly in the form of solar, will continue unabated, above and beyond the NC REPS requirements, driven by continued expected technology cost declines, local, state, and/or Federal incentives for these technologies, and PURPA implementation unique to North Carolina.

NC REPS Compliance

DEC is committed to meeting the requirements of NC REPS, including the poultry waste, swine waste, and solar set-asides, and the general requirement, which will be met with additional solar, hydro, biomass, landfill gas, wind, and EE resources. NC REPS allows for compliance utilizing not only renewable energy resources supplying bundled energy, RECs, and EE, but also by procuring unbundled RECs (both in-state and out-of-state) and thermal RECs. Therefore, the

[2] Solar capacities are adjusted to account for an annual 0.50% degradation of nameplate capacity.

actual renewable energy delivered to the DEC system is impacted by the amount of EE, unbundled RECs and thermal RECs utilized for compliance.

Based on currently signed projects and projections of what will materialize from the interconnection queue to support NC REPS compliance, DEC will have a need for additional RECs to meet the general compliance requirement in the future without additional resources. DEC is therefore planning to issue a Request for Proposal (RFP) for additional renewable resources in the Fall of 2016 in support of its compliance targets. For details of DEC's NC REPS compliance plan, please reference the NC REPS Compliance Plan attachment.
Additional information on DEC's RFP plans can be found in Chapter 9.

Solar: PURPA and the Interconnection Queue

The rapid growth of new solar facilities continues to dominate the renewable energy market landscape. As discussed above, DEC purchases solar energy from non-utility generators in North Carolina to comply with NC REPS requirements. In addition to the NC REPS compliance requirements, however, DEC is also subject to PURPA, which requires that it purchase power from QFs at its avoided cost, regardless of the utility's need for such energy. Thus, another driver of the significant growth in QF solar purchases relates to the avoided cost rates a utility must pay for this power under PURPA. The utility's avoided cost rates, as approved by the NCUC, are a critical input for forecasting renewable penetration from QFs. Expected avoided costs, which are a key input to the rates paid to solar generators, are subject to factors such as commodity price volatility, regulatory changes, system operating conditions, and weather. Therefore, determining the future value of avoided costs is not easy and cannot be done with a high degree of accuracy.

Given the currently approved avoided cost rates and standard offer terms in NC, the NC REPS mandate, continuing impacts from the 35% North Carolina Renewable Energy Investment Tax Credit Safe Harbor Provision (which expired at the end of 2015), and the 30% Federal Solar Investment Tax Credit (ITC) (which was extended in December 2015), the QF market remains very active in the DEC service territory. Illustrating this trend are these facts:

- DEC had over 300 MW-AC (includes compliance and non-compliance MW) of third-party solar facilities on its system through the end of 2015, with close to half of the facilities interconnecting in 2015.
- When renewable resources were evaluated for the 2016 IRP, DEC reported another ~140 MW of third-party solar under construction and over 900 MW in the

interconnection queue, including over 200 MW requested during the first quarter of 2016.

Projecting future solar connections from the interconnection queue, and its impact on future resource needs, presents a significant challenge as a large number of projects and interconnection requests have historically been cancelled or their ownership has changed hands numerous times. Given the size of the DEC and DEP queues, the time to complete the process from interconnection request to project completion where a facility is connected and supplying energy to the grid, often takes 2 years or more (please refer to Docket E-100 Sub 101A). The interconnection queue as of June 30, 2016 is provided in Appendix H.

While forecasting what will materialize from the current queue is difficult, projecting long-term solar growth is even more challenging. There are a number of factors that are difficult to predict, but necessary to estimate future renewable generation. These variables include, but are not limited to, interest rates, technology costs, construction and maintenance costs, energy and tax policy and operational constraints such as interconnection feasibility or land availability. In total, DEC expects 204 MW-AC of nameplate non-compliance mandated PURPA solar capacity by 2031, some of which could be converted to compliance resources.

Utility-Owned Solar and Integration

DEC continues to evaluate utility-owned solar additions to support its compliance targets and operational flexibility. For example, DEC has two new utility-scale solar projects under construction listed below which should be producing RECs and available for the summer peak of 2017:

- Monroe Solar Facility – 60MW, located in Union County; and
- Mocksville Solar Facility – 15MW, located in Davie County.

While there is uncertainty in the rate of decline in the cost of solar over time, in most scenarios evaluated in the IRP planning process, additional utility-owned solar was not selected above and beyond the total capacity expected for NC REPS compliance, PURPA puts, and customer product offerings like the Green Source Rider and SC DER. As described in more detail in Appendix A, scenarios where solar was selected required assumptions in which lower installed solar costs and/or higher emissions constraints were utilized relative to the Base Case assumptions. Such price declines may be realized, and the Company will continue to position itself for delivering quality, cost-effective projects that leverage the utility's scale and knowledge. DEC continues to build its relationships with suppliers, Engineering, Procurement, and Construction Contractors (EPCs), and other entities to create greater efficiencies in the supply chain, reduce construction costs, reduce operating and maintenance costs (O&M), and enhance system design. DEC will continue to evaluate how to increase its ownership of renewable generation to expand its portfolio of clean energy resources, meet future customer demand, and comply with evolving government regulations that promote the use of such resources.

Positioning itself to properly integrate renewable resources to the grid, especially solar, is critical. The Company is already observing that significant volumes of solar capacity result in excess energy challenges during the middle of the day during mild conditions when overall system demand is low. As a result, the Company sees an increasing need for operational control of the solar facilities connected to the grid. Additionally, the intermittency of solar output will require the Company to evaluate and invest in technologies to provide solutions for voltage, (Volt Ampere Reactive) VaR, and/or higher ancillary reserve requirements. DEC expects that it can safely and reliably integrate renewable resources like solar through a combination of utility-owned assets and cooperation with third parties. DEC will evaluate the potential for acquiring facilities, where appropriate, to help ensure the Company has needed operational control, while minimizing the costs associated with system integration.

SC DER Solar and Customer Program Solar

In addition to PURPA and NC REPS compliance solar, solar growth has also been embraced with customer-oriented strategies such as the Green Source Rider and SC DER. The Green Source Rider allows DEC to procure renewable energy on behalf of the customer. The customer pays for the REC during their project term and DEC may acquire the REC following the contract term. Customers such as Cisco and Google have participated in this program, which is anticipated to grow to 102 MW-AC (nameplate capacity) by 2017. DEC is evaluating additional programs similar to the Green Source Rider as companies nationwide have demonstrated a desire for solar to support growing sustainability goals. For example, technology companies that often have data centers have signed around 1 GW of renewable energy PPAs nationally from 2015-June 2016.

In 2015, the Company's DER plan was approved by the PSCSC, thus allowing the Company to pursue a portfolio of initiatives designed to increase the solar capacity located in the Company's South Carolina service area. The program contains three tiers; each is equivalent to 1% of the

Company's estimated average South Carolina retail peak demand (or 40 MW of nameplate solar capacity). The plan calls for a total of ~120MW of solar capacity[3] distributed across three tiers:

- Tier I: 40 MW of solar capacity from facilities each >1 MW and less than 10 MW in size.
- Tier II: 40 MW met via behind-the-meter rooftop solar facilities ≤1 MW for residential, commercial, and industrial customers with at least a quarter of that capacity from facilities each ≤ 20 kilowatts (kW). Since Tier II is behind the meter, the expected solar generation is embedded in the load forecast as a reduction to expected load.
- Tier III: Investment by the utility in 40 MW of solar capacity from facilities each >1 MW and less than 10 MW in size. Upon completion of Tiers I and II (to occur no later than 2021), the Company can directly invest in additional solar generation to complete Tier III.

In DEC-South Carolina, as part of the SC DER plan, the Company launched its first Shared Solar program. Often called "community solar," shared solar refers to both a solar facility and a billing structure in which multiple customers subscribe to and share in the economic benefits of the output of a single solar facility. The Company designed its initial SC DER shared solar program such that it would have strong appeal to residential and commercial customers who rent or lease their premise, to residential customers who reside in multifamily housing units or shaded housing, and to residential customers for whom the relatively high up-front costs of solar photovoltaic (PV) make net metering unattainable. The Company is evaluating the potential for a shared solar offer to North Carolina customers. Furthermore, the Company continues to study the potential for programs that support more load-centered rooftop solar PV installation in North Carolina.

Battery Storage and Wind

In addition to solar, the Company is assessing renewable technologies such as battery storage and wind. Battery storage costs are expected to decline significantly which may make it a viable option in the long run to support operational challenges caused by uncontrolled solar penetration. In the short run, battery storage is expected to be used primarily to support localized distribution based issues.

Similar to solar, at the end of 2015, wind received a boost from the announcement of a multi-year extension of the wind energy Production Tax Credit (PTC). Investing in wind inside of DEC's

[3] 1% of the Company's South Carolina retail peak is equal to approximately 40 MW.

footprint is unlikely in the short term in spite of the PTC. This is primarily due to a lack of suitable sites and permitting challenges, as well as less significant expected drops in capital costs compared to other renewable technologies like solar. As discussed in the NC REPS compliance plan however, additional opportunities may be pursued to transmit wind energy from out of state regions where wind is more prevalent and into the Carolinas.

Summary of Expected Renewable Resource Capacity Additions

The 2016 IRP incorporated three different renewable capacity forecasts: Low Case, Base Case, and High Case. Each of these cases includes renewable capacity required for compliance with NC REPS, non-compliance PURPA renewable purchases, as well as SC DER, Green Source Rider, and other solar capacity associated with customer programs. The Company anticipates a diverse portfolio including solar, biomass, hydro, and other resources. Actual results could vary substantially depending on the uncertainties listed above as well as other potential changes to future legislative requirements, supportive tax policies, technology, and other market forces. The details of the forecasted capacity additions, including both nameplate and contribution to winter and summer peaks are summarized in Table 5-A below.

While solar doesn't normally reach its maximum output at the time of DEC's expected peak load in the summer, solar's contribution to summer peak (net of solar) load is large enough (46% of nameplate solar capacity) that it may push the time of summer peak from hour beginning 4:00 PM to 5:00 PM or later if solar penetration levels continue to increase. Note, however, that solar is unlikely to have a similar impact on the morning winter peak (net of solar) due to lower expected solar output in the morning hours (5% of nameplate solar capacity contribution).

Table 5-A DEC Base Case Total Renewables

DEC Base Renewables - Compliance + Non-Compliance										
	MW Nameplate			MW Contribution to Summer Peak			MW Contribution to Winter Peak			
	Solar	Biomass/ Hydro	Total	Solar	Biomass/ Hydro	Total		Solar	Biomass/ Hydro	Total
2017	735	98	833	338	98	436	2016/2017	37	98	135
2018	907	81	989	417	81	499	2017/2018	45	81	127
2019	1088	74	1162	501	74	575	2018/2019	54	74	128
2020	1244	73	1317	572	73	645	2019/2020	62	73	135
2021	1416	70	1486	651	70	722	2020/2021	71	70	141
2022	1542	66	1607	709	66	775	2021/2022	77	66	143
2023	1641	62	1703	755	62	817	2022/2023	82	62	144
2024	1724	62	1786	793	62	855	2023/2024	86	62	148
2025	1801	61	1861	828	61	889	2024/2025	90	61	151
2026	1873	55	1928	862	55	917	2025/2026	94	55	149
2027	1941	49	1990	893	49	942	2026/2027	97	49	146
2028	2004	44	2048	922	44	966	2027/2028	100	44	144
2029	2063	44	2107	949	44	993	2028/2029	103	44	147
2030	2118	44	2161	974	44	1018	2029/2030	106	44	150
2031	2168	34	2202	997	34	1031	2030/2031	108	34	142

* Solar includes 0.5% per year degradation

Given the significant volume and uncertainty around solar penetration, high and low solar portfolios were evaluated compared to the Base Case described above. The portfolios don't envision a specific market condition, but rather the potential combined effect of a number of factors. For example, the high sensitivity could occur given events such as high carbon prices, lower solar capital costs, economical solar plus storage, continuation of renewal subsidies, and/or stronger renewable energy mandates. On the other hand, the low sensitivity may occur given events such as lower fuel prices for more traditional generation technologies, higher solar installation and interconnection costs, lower avoided costs, and/or less favorable PURPA terms. Tables 5-B and 5-C below provide the high and low solar nameplate capacity summaries as well as their corresponding expected contributions to summer and winter peaks.

Table 5-B DEC High Case Total Renewables

DEC High Renewables - Compliance + Non-Compliance										
	MW Nameplate			MW Contribution to Summer Peak			MW Contribution to Winter Peak			
	Solar	Biomass/ Hydro	Total	Solar	Biomass/ Hydro	Total		Solar	Biomass/ Hydro	Total
2017	805	98	903	370	98	468	2016/2017	40	98	138
2018	1057	81	1138	486	81	567	2017/2018	53	81	134
2019	1249	74	1323	575	74	649	2018/2019	62	74	136
2020	1436	73	1509	661	73	734	2019/2020	72	73	145
2021	1609	70	1679	740	70	810	2020/2021	80	70	150
2022	1810	66	1876	832	66	898	2021/2022	90	66	156
2023	1990	62	2052	915	62	977	2022/2023	100	62	162
2024	2140	62	2202	984	62	1046	2023/2024	107	62	169
2025	2281	61	2342	1049	61	1110	2024/2025	114	61	175
2026	2413	55	2468	1110	55	1165	2025/2026	121	55	176
2027	2537	49	2586	1167	49	1216	2026/2027	127	49	176
2028	2654	44	2698	1221	44	1265	2027/2028	133	44	177
2029	2763	44	2807	1271	44	1315	2028/2029	138	44	182
2030	2864	44	2908	1317	44	1361	2029/2030	143	44	187
2031	2957	34	2991	1360	34	1394	2030/2031	148	34	182

* Solar includes 0.5% per year degradation

Table 5-C DEC Low Case Total Renewables

DEC Low Renewables - Compliance + Non-Compliance										
	MW Nameplate			MW Contribution to Summer Peak			MW Contribution to Winter Peak			
	Solar	Biomass/ Hydro	Total	Solar	Biomass/ Hydro	Total		Solar	Biomass/ Hydro	Total
2017	735	98	833	338	98	436	2016/2017	37	98	135
2018	887	81	968	408	81	489	2017/2018	44	81	125
2019	1042	74	1116	479	74	553	2018/2019	52	74	126
2020	1178	73	1251	542	73	615	2019/2020	59	73	132
2021	1334	70	1404	614	70	684	2020/2021	67	70	137
2022	1427	66	1493	656	66	722	2021/2022	71	66	137
2023	1507	62	1569	693	62	755	2022/2023	75	62	137
2024	1574	62	1636	724	62	786	2023/2024	79	62	141
2025	1636	61	1697	753	61	814	2024/2025	82	61	143
2026	1695	55	1750	780	55	835	2025/2026	85	55	140
2027	1750	49	1799	805	49	854	2026/2027	88	49	137
2028	1801	44	1845	828	44	872	2027/2028	90	44	134
2029	1848	44	1892	850	44	894	2028/2029	92	44	136
2030	1892	44	1936	870	44	914	2029/2030	95	44	139
2031	1932	34	1966	889	34	923	2030/2031	97	34	131

* Solar includes 0.5% per year degradation

6. SCREENING OF GENERATION ALTERNATIVES

As previously discussed, the Company develops the load forecast and adjusts for the impacts of EE programs that have been pre-screened for cost-effectiveness. The growth in this adjusted load forecast and associated reserve requirements, along with existing unit retirements or purchased power contract expirations, creates a need for future generation. This need is partially met with demand side management (DSM) resources and the renewable resources required for compliance with NC REPS. The remainder of the future generation needs can be met with a variety of potential supply side technologies.

For purposes of the 2016 IRP, the Company considered a diverse range of technology choices utilizing a variety of different fuels, including ultra-supercritical pulverized coal (USCPC) units with carbon capture and sequestration (CCS), integrated gasification combined cycle (IGCC) with CCS, CTs, CCs with inlet chillers and duct firing, Combined Heat and Power, reciprocating engines, and nuclear units. In addition, Duke Energy Carolinas considered renewable technologies such as wind, solar, battery storage and landfill gas in the screening analysis.

For the 2016 IRP screening analysis, the Company screened technology types within their own respective general categories of baseload, peaking/intermediate and renewable, with the ultimate goal of screening to pass the best alternatives from each of these three categories to the integration process. As in past years, the reason for the initial screening analysis is to determine the most viable and cost-effective resources for further evaluation. This initial screening evaluation is necessary to narrow down options to be further evaluated in the quantitative analysis process as discussed in Appendix A.

The results of these screening processes determine a smaller, more manageable subset of technologies for detailed analysis in the expansion planning model. The following list details the technologies that were evaluated in the screening analysis phase of the IRP process. The technical and economic screening is discussed in detail in Appendix F.

Dispatchable (Summer Ratings)

- Base load – 782 MW Ultra-Supercritical Pulverized Coal with CCS
- Base load – 557 MW 2x1 IGCC with CCS
- Base load – 2 x 1,117 MW Nuclear Units (AP1000)
- Base load – 576 MW – 1x1x1 Advanced Combined Cycle (Inlet Chiller and Fired)
- Base load – 1,160 MW – 2x2x1 Advanced Combined Cycle (Inlet Chiller and Fired)
- Base load – 20 MW – Combined Heat & Power (CHP)

- Peaking/Intermediate – 166 MW 4 x LM6000 Combustion Turbines
- Peaking/Intermediate – 201 MW 12 x Reciprocating Engine Plant
- Peaking/Intermediate – 870 MW 4 x 7FA.05 Combustion Turbines
- Renewable – 2 MW / 8 MWh Li-ion Battery
- Renewable – 5 MW Landfill gas

Non-Dispatchable

- Renewable – 150 MW Wind - On-Shore
- Renewable – 5 MW Solar PV

7. RESOURCE ADEQUACY

Background

Resource adequacy refers to the ability of the electric system to supply the aggregate electrical demand and energy requirements of the end-use customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements. Utilities require a margin of reserve generating capacity in order to provide reliable service. Periodic scheduled outages are required to perform maintenance, inspections of generating plant equipment, and to refuel nuclear plants. Unanticipated mechanical failures may occur at any given time, which may require shutdown of equipment to repair failed components. Adequate reserve capacity must be available to accommodate these unplanned outages and to compensate for higher than projected peak demand due to forecast uncertainty and weather extremes. The Company utilizes a reserve margin target in its IRP process to ensure resource adequacy. Reserve margin is defined as total resources minus peak demand, divided by peak demand. The reserve margin target is established based on probabilistic assessments as described below.

In 2012, the Company retained Astrape Consulting to conduct a resource adequacy study to determine the level of reserves needed to maintain adequate generation system reliability. Based on results of the 2012 Astrape analysis, the Company adopted a 14.5% minimum summer planning reserve margin for scheduling new resource additions.

In 2016, the Company again retained Astrape Consulting to conduct an update to the resource adequacy study performed in 2012. The updated study was warranted due to two primary factors. First, the extreme weather experienced in the service territory in recent winter periods was so impactful to the system that additional review with the inclusion of recent years' weather history was warranted. Second, since the last resource adequacy study the system has added, and projects to add, a large amount of resources that provide meaningful capacity benefits in the summer. From a peak reduction perspective, summer-oriented resources include summer load control programs, chiller additions to natural gas combined cycle units, and solar generation. Solar resources contribute approximately 46% of nameplate capacity at the time of the expected summer peak demand and only about 5% of nameplate capacity at the time of expected winter peak demand. The interconnection queue for solar facilities shows the potential to add significantly to the solar resources already incorporated on the system.

2016 Resource Adequacy Study Results

Astrape conducted an updated resource adequacy assessment in 2016 that incorporated the uncertainty of weather, economic load growth, unit availability, and the availability of transmission and generation capacity for emergency assistance. Astrape analyzed the optimal planning reserve margin based on providing an acceptable level of physical reliability and minimizing economic costs to customers. The most common physical reliability metric used in the industry is to target a system reserve margin that satisfies the one day in 10 years Loss of Load Expectation (LOLE) standard. This standard is interpreted as one firm load shed event every 10 years due to a shortage of generating capacity. From an economic perspective, as planning reserve margin increases, the total cost of reserves increases while the costs related to reliability events decline. Similarly, as planning reserve margin decreases, the cost of reserves decreases while the costs related to reliability events increase, including the costs to customers for loss of power. Thus, there is an economic optimum point where the cost of additional reserves plus the cost of reliability events to customers is minimized.

In the past, loss of load risk has typically been concentrated during the summer months and a summer reserve margin target provided adequate reserves in the summer and winter and was thus sufficient for ensuring resource adequacy. However, the incorporation of recent winter load data and the significant amount of solar penetration in the updated study, shows that the majority of loss of load risk is now heavily concentrated during the winter period. Since solar capacity contribution to peak is much greater in the summer compared to the winter, use of a summer reserve margin target will no longer ensure that adequate reserve levels are maintained in the winter. As a result, a winter planning reserve margin target is now needed to ensure that adequate resources are available throughout the year to meet customer demand.

Based on results of the 2016 resource adequacy assessment, the Company has adopted a 17% minimum winter reserve margin target for scheduling new resource additions. Astrape also recommends maintaining a 15% minimum summer reserve margin to ensure adequate reliability is maintained during the summer period. However, given the portfolio of existing and projected new resources, a 15% summer reserve margin will always be satisfied if a 17% winter reserve margin is maintained. The Company will continue to monitor its generation portfolio and other planning assumptions that can impact resource adequacy and initiate new studies as appropriate.

Adequacy of Projected Reserves

DEC's resource plan reflects winter reserve margins ranging from approximately 17% to 22%. Reserves projected in DEC's IRP meet the minimum planning reserve margin target and thus satisfy the one day in 10 years LOLE criterion. The projected reserve margin exceeds the minimum 17% winter target by 3% or more in 2017/18 and 2018/19 as a result of the Lee combined-cycle addition in November 2017. The reserve margin exceeds the minimum target by 3% in 2022/23 and 2023/24 due to the addition of a large combined cycle unit in December 2022. Also, the reserve margin exceeds the minimum target by 3% in 2026/27 due to the addition of a baseload nuclear unit in November 2026.

The IRP provides general guidance in the type and timing of resource additions. Since capacity is generally added in large blocks to take advantage of economies of scale, it should be noted that projected planning reserve margins in years immediately following new generation additions will often be somewhat higher than the minimum target. Large resource additions are deemed economic only if they have a lower Present Value Revenue Requirement (PVRR) over the life of the asset as compared to smaller resources that better fit the short-term reserve margin need. Reserves projected in DEC's IRP are appropriate for providing an economic and reliable power supply.

8. EVALUATION AND DEVELOPMENT OF THE RESOURCE PLAN

As described in the previous chapter, DEC has added a winter planning reserve margin criteria to the IRP process. To meet the future needs of DEC's customers, it is necessary for the Company to adequately understand the load and resource balance. For each year of the planning horizon, DEC develops a load forecast of cumulative energy sales and hourly peak demand. To determine total resources needed, the Company considers the peak demand load obligation plus a 17% minimum planning winter reserve margin. The projected capability of existing resources, including generating units, EE and DSM, renewable resources and purchased power contracts is measured against the total resource need. Any deficit in future years will be met by a mix of additional resources that reliably and cost-effectively meet the load obligation and planning reserve margin while complying with all environmental and regulatory requirements. It should be noted that DEC considers the non-firm energy purchases and sales associated with the Joint Dispatch Agreement (JDA) with DEP in the development of its independent Base Case and five alternative portfolios as discussed later in this chapter and in Appendix A.

IRP Process

The following section summarizes the Data Input, Generation Alternative Screening, Portfolio Development and Detailed Analysis steps in the IRP process. A more detailed discussion of the IRP Process and development of the Base Case and additional portfolios is provided in Appendix A.

Data Inputs

The initial step in the IRP development process is one of input data refreshment and revision. For the 2016 IRP, data inputs such as load forecast, EE and DSM projections, fuel prices, projected CO_2 prices, individual plant operating and cost information, and future resource information were updated with the most current data. These data inputs were developed and provided by Company subject matter experts and/or based upon vendor studies, where available. Furthermore, DEC and DEP continue to benefit from the combined experience of both utilities' subject matter experts utilizing best practices from each utility in the development of their respective IRP inputs. Where appropriate, common data inputs were utilized.

As expected, certain data elements and issues have a larger impact on the IRP than others. Any changes in these elements may result in a noticeable impact to the plan, and as such, these elements are closely monitored. Some of the most consequential data elements are listed below. A detailed discussion of each of these data elements has been presented throughout this document and are examined in more detail in the appendices.

- Load Forecast for Customer Demand
- EE/DSM
- Renewable Resources and Cost Projections
- Fuel Costs Forecasts
- Technology Costs and Operating Characteristics
- Environmental Legislation and Regulation

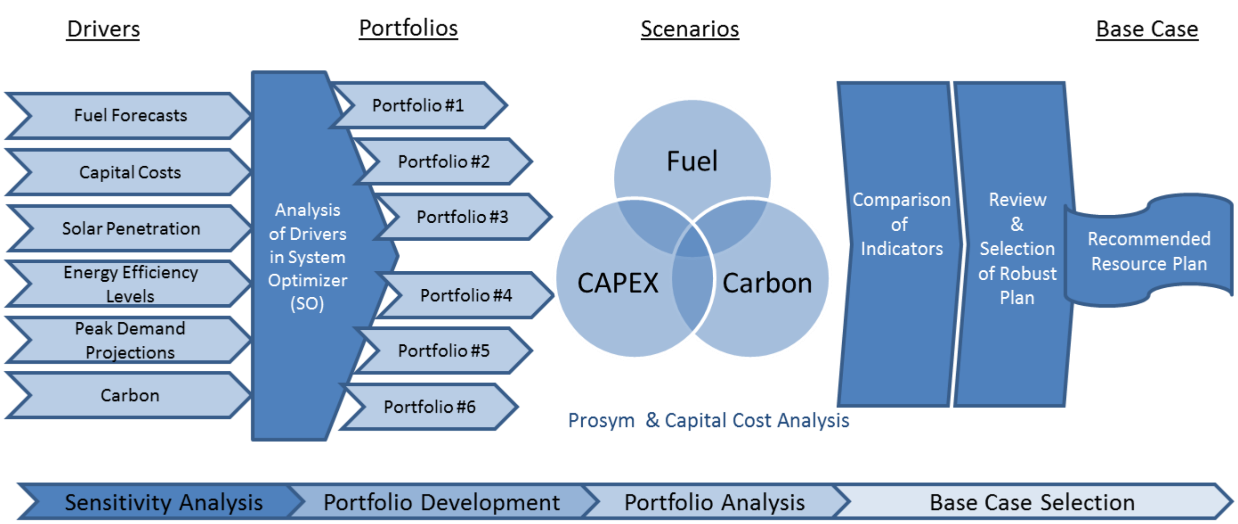
Generation Alternative Screening

DEC reviews generation resource alternatives on a technical and economic basis. Resources must also be demonstrated to be commercially available for utility scale operations. The resources that are found to be both technically and economically viable are then passed to the detailed analysis process for further analysis.

Portfolio Development and Detailed Analysis

The following figure provides an overview of the process for the portfolio development and detailed analysis phase of the IRP.

Figure 8-A Overview of Portfolio Development and Detailed Analysis Phase



The Sensitivity Analysis and Portfolio Development phases rely upon the updated data inputs and results of the generation alternative screening process to derive resource portfolios or resource plans. The Sensitivity Analysis and Portfolio Development phases utilize an expansion planning model to determine the best mix of capacity additions for the Company's short- and long-term resource needs with an objective of selecting a robust plan that minimizes the PVRR and is environmentally sound complying with all State and Federal regulations.

Sensitivity analysis of input variables such as load forecast, fuel costs, renewable energy, EE, and capital costs are considered as part of the quantitative analysis within the resource planning process. Utilizing the results of these sensitivities, possible expansion plan options for the DEC system are developed. These expansion plans are reviewed to determine if any overarching trends are present across the plans, and based on this analysis, specific portfolios are developed to represent these trends. Finally, the portfolios are analyzed using a capital cost model and an hourly production cost model (PROSYM) under various fuel price, capital cost and carbon scenarios to evaluate the robustness and economic value of each portfolio, and at this point, the Base Case portfolio is selected.

In addition to evaluating these portfolios solely within the DEC system, the potential benefits of sharing capacity within DEC and DEP are examined in a common Joint Planning Case. A detailed discussion of these portfolios is provided in Appendix A.

Selected Portfolios

For the 2016 IRP, six representative portfolios were identified through the Sensitivity Analysis and Portfolio Development steps. Four of the portfolios were developed under a Carbon Tax paradigm where varying levels of an intrastate CO_2 tax were applied to existing coal and gas units as envisioned in EPA's Clean Power Plan. Three of these portfolios included Lee Nuclear Plant in 2026 and 2028 and varied levels of EE and renewable penetration, while the fourth portfolio replaced Lee Nuclear plant with mainly CC generation.

The remaining two portfolios were developed under a System CO_2 Mass Cap that represented an alternative outcome of the CPP. In these portfolios total system CO_2 emissions were constrained starting in 2022 and declined until 2030, and total system emission were held flat from 2030 throughout the remaining planning horizon.

One of these portfolios included base EE and base renewable assumptions, while the other portfolio included higher levels of EE and renewables. In general, both of these portfolios required relicensing or replacement of existing nuclear generation along with construction of the Lee Nuclear Plant in the late 2020s to keep carbon emissions flat to declining.

Portfolio Analysis & Base Case Selection

The six portfolios identified in the screening analysis were evaluated in more detail with an hourly production cost model under several scenarios. The four scenarios are summarized in Table 8-A and included sensitivities on fuel, carbon, and capital cost.

Table 8-A Scenarios for Portfolio Analysis

	Carbon Tax/No Carbon Tax Scenarios[1]	**Fuel**	**CO_2**	**CAPEX**
1	Current Trends	Base	CO_2 Tax	Base
2	Economic Recession	Low Fuel	No CO_2 Tax	Low
3	Economic Expansion	High Fuel	CO_2Tax	High

[1]Run Portfolios 1 - 4 through each of these 3 scenarios

	System Mass Cap Scenarios[2]	**Fuel**	**CO_2**	**CAPEX**
4	Current Trends - CO_2 Mass Cap	Base	Mass Cap	Base

[2]Run Portfolios 5 - 6 through this single MC2 scenario

Portfolios 1 through 4 were analyzed under a current economic trend scenario (Scenario #1), an economic recession scenario (Scenario #2), and an economic expansion scenario (Scenario #3). Portfolios 5 & 6 were only evaluated under the Current Trends – System Mass Cap scenario (Scenario #4).

Under a cap on system carbon emissions, fuel price and capital cost will have little impact on the optimization of the system as the carbon output of the various generators will control dispatch to a greater extent than the fuel price.

Table 8-B lists the Portfolios that were developed under a Carbon Tax paradigm, along with their PVRR rankings under the three scenarios.

Table 8-B: Portfolios 1 – 4 PVRR Rankings

Portfolio	Scenario #1 (Current Trends)	Scenario #2 (Economic Recession)	Scenario #3 (Economic Expansion)
Portfolio #1 Base Case	2	2	2
Portfolio #2 (High Renew)	4	4	4
Portfolio #3 (High EE)	3	3	3
Portfolio #4 (High CC)	1	1	1

While Portfolio #4 had the lowest PVRR due to the absence of Lee Nuclear, Portfolio #4 was not selected as the Base Case because it's carbon footprint would not be sustainable over the long term in a System CO_2 Mass Cap plan if new nuclear generation was not available in the late 2020s. Portfolios 1 through 3 add Lee Nuclear Station in the 2026-2028 timeframe, which leads to a reduction in CO_2 emissions of about 15% to 20% by 2030. Portfolio #1 is the least cost portfolio with Lee Nuclear Station included, but none of these portfolios would meet a System CO_2 Mass Cap scenario unless existing nuclear generation was relicensed or replaced with new nuclear generation.

Future CO_2 legislation is still uncertain, and a system mass cap on carbon emissions is still a possibility. The short term build plan from Portfolio #1 (Base Case with Lee Nuclear) would keep the Company on track if a System CO_2 Mass Cap were implemented. Of the portfolios that included Lee Nuclear, Portfolio #1 was the least cost portfolio from a revenue requirements perspective.

Based on the PVRR Rankings, the robustness of the portfolio, and the belief that there will be some type of carbon legislation in the future, Portfolio #1 was selected as the Base Case under a Carbon Tax paradigm in the 2016 IRP.

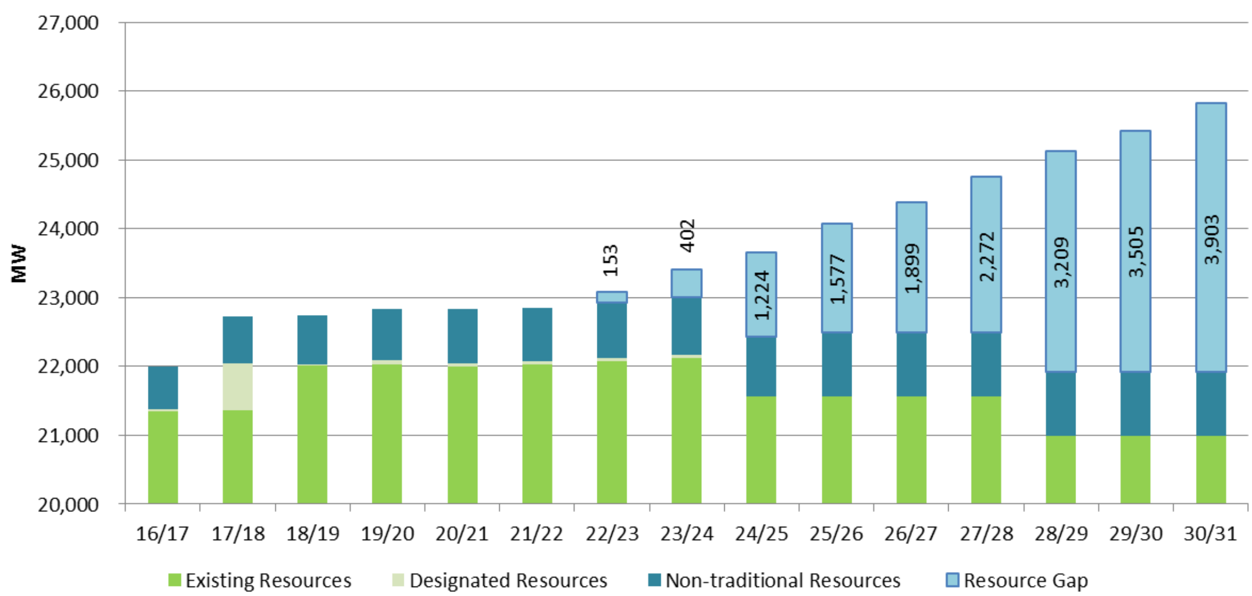
Finally, Portfolios 5 and 6 were evaluated under the Current Trends scenario with a System Mass Cap carbon constraint. Under the Mass Cap carbon paradigm, the high EE and high renewable combination led to a slightly higher PVRR versus the Base Case. The capital costs of the high EE/high renewable portfolio was nearly \$1.9B higher than Portfolio #5, however, this was largely offset by approximately \$1.7B in system production cost savings. Given the lower cost and uncertainty of achieving the high EE targets, Portfolio #5 was selected to represent the Base Case under a System Mass Cap carbon plan.

Base Case

The Base Case was selected based upon the evaluation of the portfolios in the Carbon Tax paradigm. The Base Case was developed utilizing consistent assumptions and analytic methods between DEC and DEP, where appropriate. This case does not take into account the sharing of capacity between DEC and DEP. However, the Base Case incorporates the JDA between DEC and DEP, which represents a non-firm energy only commitment between the Companies. A Joint Planning Case that begins to explore the potential for DEC and DEP to share firm capacity was also developed and is discussed later in this chapter and in Appendix A.

The Load and Resource Balance Chart shown in Chart 8-A illustrates the resource needs that are required for DEC to meet its load obligation inclusive of a required reserve margin. The existing generating resources, designated resource additions and EE resources do not meet the required load and reserve margin beginning in 2023. As a result, the resource plan analyses described above have determined the most robust plan to meet this resource gap.

Chart 8-A DEC Base Case Load Resource Balance (Winter)



Cumulative Resource Additions to Meet Winter Load Obligation and Reserve Margin (MW)

Year	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24
Resource Need	0	0	0	0	0	0	153	402
Year	24/25	25/26	26/27	27/28	28/29	29/30	30/31	
Resource Need	1,224	1,577	1,899	2,272	3,209	3,505	3,903	

Tables 8-C and 8-D present the Load, Capacity and Reserves (LCR) tables for the Base Case analysis that was completed for DEC's 2016 IRP.

Table 8-C Load, Capacity and Reserves Table - Winter

Winter Projections of Load, Capacity, and Reserves
for Duke Energy Carolinas 2016 Annual Plan

		16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27	27/28	28/29	29/30	30/31
Load Forecast																
1	Duke System Peak	18,520	18,819	18,916	19,195	19,513	19,764	20,071	20,389	20,638	21,003	21,290	21,609	21,929	22,193	22,530
2	Firm Sale	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Cumulative New EE Programs	(57)	(107)	(148)	(191)	(254)	(298)	(340)	(379)	(415)	(433)	(446)	(447)	(452)	(459)	(461)
4	**Adjusted Duke System Peak**	**18,463**	**18,712**	**18,768**	**19,004**	**19,259**	**19,466**	**19,731**	**20,011**	**20,223**	**20,570**	**20,844**	**21,161**	**21,478**	**21,734**	**22,068**
Existing and Designated Resources																
5	Generating Capacity	21,132	21,141	21,824	21,834	21,900	21,946	21,993	22,039	22,085	21,481	21,481	21,481	21,481	20,924	20,924
6	Designated Additions / Uprates	25	683	10	66	46	46	46	46	-	-	-	-	-	-	-
7	Retirements / Derates	(16)	-	-	-	-	-	-	-	(604)	-	-	-	(557)	-	-
8	**Cumulative Generating Capacity**	**21,141**	**21,824**	**21,834**	**21,900**	**21,946**	**21,993**	**22,039**	**22,085**	**21,481**	**21,481**	**21,481**	**21,481**	**20,924**	**20,924**	**20,924**
Purchase Contracts																
9	**Cumulative Purchase Contracts**	**251**	**261**	**232**	**231**	**141**	**118**	**119**	**120**	**121**	**122**	**117**	**118**	**105**	**106**	**107**
	Non-Compliance Renewable Purchases	33	34	38	39	39	40	40	40	40	40	34	34	34	34	34
	Non-Renewables Purchases	217	227	195	192	101	79	79	80	81	82	83	84	71	72	73
Undesignated Future Resources																
10	Nuclear											1,117		1,117		
11	Combined Cycle							1,221								
12	Combustion Turbine									468						
Renewables																
13	**Cumulative Renewables Capacity**	101	92	91	96	102	103	104	108	111	109	112	109	112	115	108
14	**Combined Heat & Power**	-	43	22	22	22	-	-	-	-	-	-	-	-	-	-
15	**Cumulative Production Capacity**	**21,493**	**22,221**	**22,222**	**22,314**	**22,297**	**22,322**	**23,592**	**23,643**	**23,511**	**23,509**	**24,625**	**24,623**	**25,174**	**25,177**	**25,171**
Demand Side Management (DSM)																
16	**Cumulative DSM Capacity**	**490**	**501**	**513**	**526**	**538**	**535**	**562**	**589**	**616**	**670**	**670**	**669**	**669**	**669**	**669**
17	**Cumulative Capacity w/ DSM**	**21,983**	**22,722**	**22,735**	**22,839**	**22,835**	**22,857**	**24,153**	**24,232**	**24,126**	**24,179**	**25,294**	**25,292**	**25,843**	**25,847**	**25,840**
Reserves w/ DSM																
18	Generating Reserves	3,520	4,010	3,967	3,836	3,577	3,391	4,422	4,221	3,903	3,609	4,450	4,131	4,365	4,113	3,772
19	**% Reserve Margin**	**19%**	**21%**	**21%**	**20%**	**19%**	**17%**	**22%**	**21%**	**19%**	**18%**	**21%**	**20%**	**20%**	**19%**	**17%**

Table 8-D Load, Capacity and Reserves Table – Summer

Summer Projections of Load, Capacity, and Reserves
for Duke Energy Carolinas 2016 Annual Plan

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Load Forecast															
1 Duke System Peak	18,877	19,159	19,183	19,446	19,685	19,933	20,229	20,521	20,837	21,130	21,405	21,712	21,998	22,297	22,603
2 Firm Sale	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3 Cumulative New EE Programs	(102)	(164)	(220)	(272)	(323)	(371)	(425)	(475)	(516)	(549)	(564)	(566)	(572)	(574)	(575)
4 Adjusted Duke System Peak	**18,776**	**18,995**	**18,963**	**19,174**	**19,362**	**19,562**	**19,804**	**20,046**	**20,321**	**20,581**	**20,842**	**21,146**	**21,427**	**21,723**	**22,028**
Existing and Designated Resources															
5 Generating Capacity	20,394	20,378	21,031	21,086	21,138	21,185	21,231	21,278	21,278	20,693	20,693	20,693	20,151	20,151	20,151
6 Designated Additions / Uprates	0	653	55	52	46	46	46	0	0	0	0	0	0	0	0
7 Retirements / Derates	(16)	0	0	0	0	0	0	0	(585)	0	0	(542)	0	0	0
8 Cumulative Generating Capacity	**20,378**	**21,031**	**21,086**	**21,138**	**21,185**	**21,231**	**21,278**	**21,278**	**20,693**	**20,693**	**20,693**	**20,151**	**20,151**	**20,151**	**20,151**
Purchase Contracts															
9 Cumulative Purchase Contracts	**348**	**367**	**365**	**371**	**292**	**275**	**275**	**276**	**276**	**277**	**272**	**272**	**259**	**260**	**261**
Non-Compliance Renewable Purchases	137	146	176	185	192	197	196	196	195	195	189	189	188	188	188
Non-Renewables Purchases	211	221	189	186	100	79	79	80	81	82	83	84	71	72	73
Undesignated Future Resources															
10 Nuclear											1,117	1,117			
11 Combined Cycle							1,123								
12 Combustion Turbine									435						
Renewables															
13 **Cumulative Renewables Capacity**	299	353	398	460	530	578	621	659	694	722	753	777	804	830	843
14 **Combined Heat & Power**	0	40	20	20	20	0	0	0	0	0	0	0	0	0	0
15 Cumulative Production Capacity	**21,025**	**21,791**	**21,909**	**22,049**	**22,107**	**22,184**	**23,397**	**23,435**	**23,321**	**23,349**	**24,492**	**25,092**	**25,106**	**25,132**	**25,147**
Demand Side Management (DSM)															
16 Cumulative DSM Capacity	**1,057**	**1,090**	**1,119**	**1,148**	**1,156**	**1,154**	**1,181**	**1,208**	**1,235**	**1,289**	**1,290**	**1,290**	**1,290**	**1,290**	**1,290**
17 Cumulative Capacity w/ DSM	**22,082**	**22,880**	**23,028**	**23,197**	**23,263**	**23,339**	**24,578**	**24,644**	**24,556**	**24,639**	**25,782**	**26,381**	**26,396**	**26,422**	**26,436**
Reserves w/ DSM															
18 Generating Reserves	3,306	3,885	4,065	4,024	3,901	3,777	4,775	4,598	4,235	4,058	4,940	5,235	4,969	4,699	4,408
19 % Reserve Margin	**18%**	**20%**	**21%**	**21%**	**20%**	**19%**	**24%**	**23%**	**21%**	**20%**	**24%**	**25%**	**23%**	**22%**	**20%**

DEC - Assumptions of Load, Capacity, and Reserves Table

The following notes are numbered to match the line numbers on the Winter Projections of Load, Capacity, and Reserves tables. All values are MW (winter ratings) except where shown as a Percent.

1. Planning is done for the peak demand for the Duke Energy Carolinas System including Nantahala.

   A firm wholesale backstand agreement for 47 MW between Duke Energy Carolinas and Piedmont Municipal Power Agency (PMPA) starts on 1/1/2014 and continues through the end of 2020. This backstand is included in Line 1.

2. No additional firm sales are included.

3. Cumulative new energy efficiency and conservation programs (does not include demand response programs).

4. Peak load adjusted for firm sales and cumulative energy efficiency.

5. Existing generating capacity reflecting designated additions, planned uprates, retirements and derates as of January 1, 2016.

   Includes 101 MW Nantahala hydro capacity, and total capacity for Catawba Nuclear Station less 832 MW to account for North Carolina Municipal Power Agency #1 (NCMPA1) firm capacity sale.

6. Capacity Additions include:

   Includes runner upgrades on each of the four Bad Creek pumped storage units. Each upgrade is expected to be 46.4 MW and are projected in the 2021 – 2024 timeframe. One unit will be upgraded per year.

   Lee Combined Cycle is reflected in 2018 (683 MW). This is the DEC capacity net of 100 MW to be owned by NCEMC.

   Capacity Additions include Duke Energy Carolinas hydro units scheduled to be repaired and returned to service. The units are returned to service in the 2017-2020 timeframe and total 16 MW.

   Also included is a 85 MW capacity increase due to nuclear uprates at Catawba and Oconee. Timing of these uprates is shown from 2017-2020.

DEC - Assumptions of Load, Capacity, and Reserves Table (cont.)

7. A planning assumption for coal retirements has been included in the 2016 IRP.

   Allen Steam Station Units 1-3 (604 MW) are assumed to retire in December 2024.

   Allen Steam Station Units 4-5 (557 MW) are assumed to retire in June 2028.

   Nuclear Stations are assumed to retire at the end of their current license extension. However, no nuclear facilities have license expiries in the 15 year study period.

   The Hydro facilities for which Duke has submitted an application to Federal Energy Regulatory Commission (FERC) for license renewal are assumed to continue operation through the planning horizon.

   All retirement dates are subject to review on an ongoing basis. Dates used in the 2016 IRP are for planning purposes only.

8. Sum of lines 5 through 7.

9. Cumulative Purchase Contracts including purchased capacity from PURPA Qualifying Facilities, an 86 MW Cherokee County Cogeneration Partners contract which began in June 1998 and expires June 2020 and miscellaneous other QF projects.

   Additional line items are shown under the total line item to show the amounts of renewable and traditional QF purchases.

   Renewable resources in these line items are not used for NC REPS compliance.

10. New nuclear resources selected to meet load and minimum planning reserve margin.

    Capacity must be on-line by June 1 to be included in available capacity for the summer peak of that year and by December 1 to be included in available capacity for the winter peak of the next year.

    Addition of 1,117 MW Lee Nuclear Unit additions assumed in November 2026 and May 2028.

11. New combined cycle resources economically selected to meet load and minimum planning reserve margin.

DEC - Assumptions of Load, Capacity, and Reserves Table (cont.)

Capacity must be on-line by June 1 to be included in available capacity for the summer peak of that year and by December 1 to be included in available capacity for the winter peak of the next year.

Addition of 1,221 MW of combined cycle capacity online December 2022.

12. New combustion turbine resources economically selected to meet load and minimum planning reserve margin.

    Capacity must be on-line by June 1 to be included in available capacity for the summer peak of that year and by December 1 to be included in available capacity for the winter peak of the next year.

    Addition of 468 MW of combustion turbine capacity online December 2024.

13. Resources to comply with NC REPS along with solar customer product offerings such as Green Source and SC DER were input as existing resources. Solar resources reflect 5% of nameplate capacity contribution at the time of winter peak demand and 46% of nameplate capacity contribution at the time of summer peak demand.

14. New 21.7 MW (winter) combined heat and power units included in 2018 (2x), 2019, 2020 and 2021. The 2016 IRP represents increased CHP resources as compared to the 2015 IRP.

15. Sum of lines 8 through 14.

16. Cumulative Demand Response programs including load control and DSDR.

17. Sum of lines 15 and 16.

18. The difference between lines 17 and 4.

19. Reserve Margin = (Cumulative Capacity-System Peak Demand)/System Peak Demand.

    Line 18 divided by Line 4.

    Minimum winter target planning reserve margin is 17%.

A tabular presentation of the Base Case resource plan represented in the above LCR table is shown below:

Table 8-E DEC Base Case

Duke Energy Carolinas Resource Plan (1) Base Case - Winter					
Year	**Resource**			**MW**	
2017	Nuclear Uprates			25	
2018	Lee CC	CHP		683	43
2019	Hydro Refurb Return to Service	CHP		10	22
2020	Nuclear Uprates	CHP	Hydro Refurb Return to Service	60 / 22	6
2021	Bad Creek Uprate	CHP		46.4	22
2022	Bad Creek Uprate			46.4	
2023	Bad Creek Uprate	New CC		46.4	1221
2024	Bad Creek Uprate			46.4	
2025	New CT			468	
2026					
2027	New Nuclear			1117	
2028					
2029	New Nuclear			1117	
2030					
2031					

Notes: (1) Table includes both designated and undesignated capacity additions
Future additions of renewables, EE and DSM not included
(2) Lee CC capacity is net of NCEMC ownership of 100 MW
(3) Rocky Creek Units currently offline for refurbishment; these are expected return to service dates
(4) Lee Nuclear in service dates are assumed to be Nov 2026 and May 2028

Additionally, a summary of the above table by fuel type is represented below in Table 8-F.

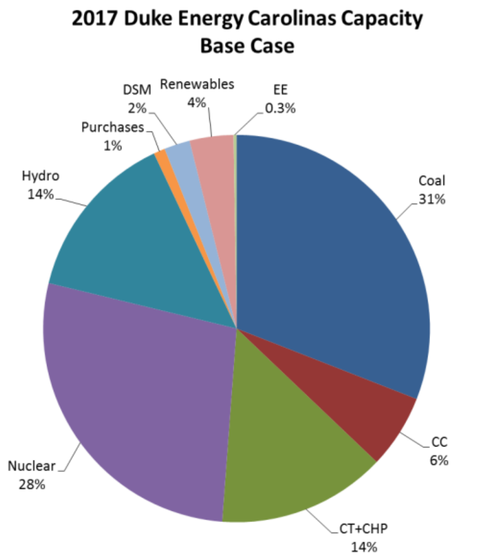
Table 8-F DEC Base Case Winter Resources by Fuel Type

DEC Base Case Resources
Cumulative Winter Totals - 2017 - 2031

Nuclear	2319
CC	1904
CT	468
Hydro	202
CHP	109
Total	5002

The following charts illustrate both the current and forecasted capacity by fuel type for the DEC system, as projected by the Base Case. As demonstrated in Chart 8-B, the capacity mix for the DEC system changes with the passage of time. In 2031, the Base Case projects that DEC will have a smaller reliance on coal and a higher reliance on gas-fired resources, nuclear, renewable resources and EE as compared to the current state. It should be noted that the Company's Base Case resources depicted in Chart 8-B below reflect a significant amount of solar capacity with nameplate solar growing from 735 MW in 2017 to 2,168 MW by 2031. However, given that solar resources only contribute 5% of nameplate capacity at the time of the Company's winter peak, solar capacity contribution to winter peak only grows from 37 MW in 2017 to 108 MW by 2031.

Chart 8-B Duke Energy Carolinas Capacity by Fuel Type – Base Case[4]



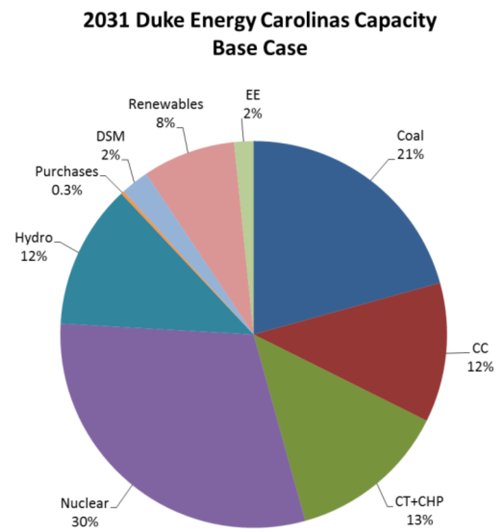
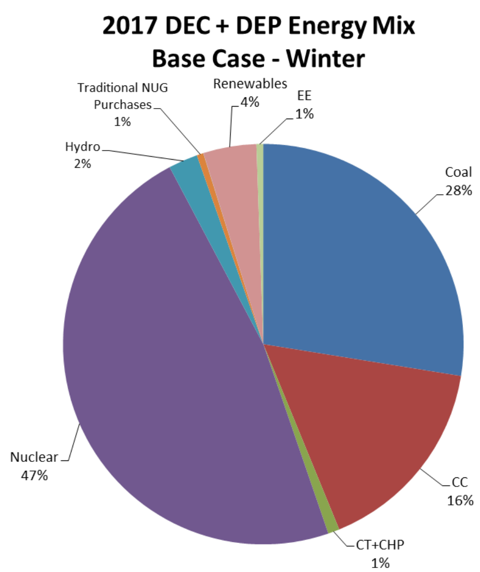
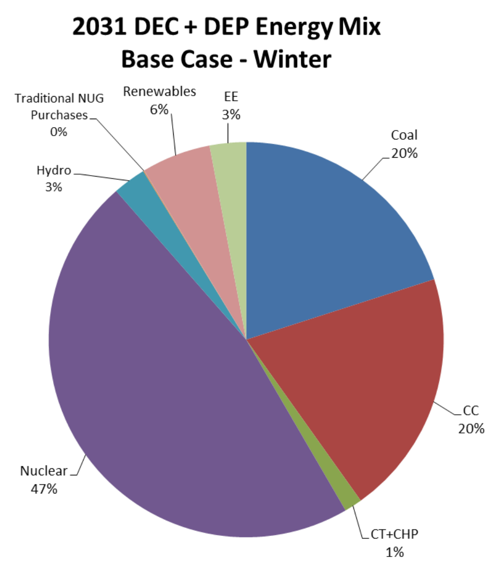


Chart 8-C represents the energy of the DEC and DEP base cases by fuel type. These energy charts represent both the DEC and DEP Base Cases. Due to the joint dispatch agreement (JDA), it is prudent to combine the energy of both utilities to develop a meaningful Base Case energy chart. From 2017 to 2031, the chart shows that nuclear resources will continue to serve almost half of DEC and DEP energy needs, a reduction in the energy served by coal, and an increase in energy served by natural gas, renewables and EE.

[4] All capacity based on winter ratings except renewables which are based on nameplate.

Chart 8-C DEC and DEP Energy by Fuel Type – Base Case[5]





A detailed discussion of the assumptions, inputs and analytics used in the development of the Base Case is contained in Appendix A. As previously noted, the further out in time planned additions or retirements are within the 2016 IRP, the greater the opportunity for input assumptions to change. Thus, resource allocation decisions at the end of the planning horizon have a greater possibility for change as compared to those earlier in the planning horizon.

System Carbon Mass Cap Case

The System Carbon Mass Cap Case assumes that total system CO_2 emissions are constrained starting in 2022 and decline until 2030, and total system emission are held flat from 2030 throughout the remaining planning horizon. In order to hold system emissions flat, new nuclear generation, along with re-licensing or replacement of existing nuclear generation, is required in the late 2020s to mid-2030s. To this point, Lee Nuclear plant is assumed to be available in November 2026 and May 2028, and additional new nuclear generation is required coincident with the retirement of Oconee Nuclear Plant in 2034. Additionally, incremental solar generation begins to be economically selected in the early 2030s as shown in Table 8-G. It should be noted that the expansion planning model does not incorporate incremental solar integration costs when selecting

[5] All capacity based on winter ratings except renewables which are based on nameplate.

resources, however these costs are added later when calculating the total PVRR of the resource plan.[6]

Table 8-G DEC System Carbon Mass Cap Case

<table>
<tr><th colspan="7">Duke Energy Carolinas Resource Plan (1)
System Mass Cap - Winter</th></tr>
<tr><th>Year</th><th colspan="3">Resource</th><th colspan="3">MW</th></tr>
<tr><td>2017</td><td colspan="3">Nuclear Uprates</td><td colspan="3">25</td></tr>
<tr><td>2018</td><td colspan="2">Lee CC</td><td>CHP</td><td colspan="2">683</td><td>43</td></tr>
<tr><td>2019</td><td colspan="2">Hydro Refurb Return to Service</td><td>CHP</td><td colspan="2">10</td><td>22</td></tr>
<tr><td>2020</td><td>Nuclear Uprates</td><td>CHP</td><td>Hydro Refurb Return to Service</td><td>66</td><td>22</td><td>6</td></tr>
<tr><td>2021</td><td colspan="2">Bad Creek Uprate</td><td>CHP</td><td colspan="2">46.4</td><td>22</td></tr>
<tr><td>2022</td><td colspan="3">Bad Creek Uprate</td><td colspan="3">46.4</td></tr>
<tr><td>2023</td><td colspan="2">Bad Creek Uprate</td><td>New CT</td><td colspan="2">46.4</td><td>468</td></tr>
<tr><td>2024</td><td colspan="3">Bad Creek Uprate</td><td colspan="3">46.4</td></tr>
<tr><td>2025</td><td colspan="3">New CC</td><td colspan="3">1221</td></tr>
<tr><td>2026</td><td colspan="3"></td><td colspan="3"></td></tr>
<tr><td>2027</td><td colspan="3">New Nuclear</td><td colspan="3">1117</td></tr>
<tr><td>2028</td><td colspan="3"></td><td colspan="3"></td></tr>
<tr><td>2029</td><td colspan="3">New Nuclear</td><td colspan="3">1117</td></tr>
<tr><td>2030</td><td colspan="3"></td><td colspan="3"></td></tr>
<tr><td>2031</td><td colspan="3">New Solar</td><td colspan="3">232</td></tr>
</table>

Notes: (1) Table includes both designated and undesignated capacity additions
Future additions of renewables, EE and DSM not included
(2) Lee CC capacity is net of NCEMC ownership of 100 MW
(3) Rocky Creek Units currently offline for refurbishment; these are expected return to service dates
(4) Lee Nuclear in service dates are assumed to be Nov 2026 and May 2028

Additionally, a summary of the above table by fuel type is represented below in Table 8-H.

[6] Solar integration costs represented in the Duke Energy Photovoltaic Integration Study published by Pacific Northwest National Lab in March 2014.

Table 8-H DEC System Carbon Mass Cap Case Winter Resources by Fuel Type

DEC System Mass Cap Resources Cumulative Winter Totals - 2017 - 2031	
Nuclear	2325
CC	1904
CT	468
Hydro	202
CHP	109
Solar	232
Total	5240

A detailed discussion of the assumptions, inputs and analytics used in the development of the System Mass Cap Case is contained in Appendix A. As previously noted, the further out in time planned additions or retirements are within the 2016 IRP, the greater the opportunity for input assumptions to change. Thus, resource allocation decisions at the end of the planning horizon have a greater possibility for change as compared to those earlier in the planning horizon.

Joint Planning Case

A Joint Planning Case that begins to explore the potential for DEC and DEP to share firm capacity between the Companies was also developed. The focus of this case is to illustrate the potential for the Utilities to collectively defer generation investment by utilizing each other's capacity when available and by jointly owning or purchasing new capacity additions. This case does not address the specific implementation methods or issues required to implement shared capacity. Rather, this case illustrates the benefits of joint planning between DEC and DEP with the understanding that the actual execution of capacity sharing would require separate regulatory proceedings and approvals.

Table 8-I below represents the annual non-renewable incremental additions reflected in the combined DEC and DEP winter Base Cases as compared to the Joint Planning Case. The plan contains the undesignated additions for DEC and DEP over the planning horizon. As presented in Table 8-I, the Joint Planning Case allows for the delay of several blocks of CT resources through the 15-year study period.

Table 8-I DEC and DEP Joint Planning Case

DEC and DEP Combined Resource Plan [1]
Base Case - Winter

Year	Resource	MW
2017		
2018		
2019		
2020		
2021		
2022	New CC	1221
2023	New CC New CT	1221 468
2024		
2025	New CT	468
2026	New CT	468
2027	New Nuclear	1117
2028	New CT	468
2029	New Nuclear New CT	1117 468
2030		
2031	New CT	1404

Notes: (1) Table only includes undesignated capacity additions.

Delay & Combine

Delay

Delay & Combine

Beyond Study Period

DEC and DEP Joint Planning Resource Plan [1]
Base Case - Winter

Year	Resource	MW
2017		
2018		
2019		
2020		
2021		
2022	New CC	1221
2023	New CC	1221
2024		
2025		
2026	New CT	936
2027	New Nuclear	1117
2028	New CT	468
2029	New Nuclear	1117
2030		
2031	New CT	1872

A comparison of both the DEC and DEP Combined Base Case and Joint Planning Base Case by fuel type is represented below in Table 8-J.

Table 8-J DEC and DEP Base Case and Joint Planning Case Comparison by Fuel Type

DEC and DEP Combined Base Case Resources
Cumulative Winter Totals - 2017 - 2031

Nuclear	2234
CC	2442
CT	3744
Total	8420

DEC and DEP Joint Base Case Resources
Cumulative Winter Totals - 2017 - 2031

Nuclear	2234
CC	2442
CT	3276
Total	7952

9. SHORT-TERM ACTION PLAN

The Company's Short-Term Action Plan, which identifies accomplishments in the past year and actions to be taken over the next five years, is summarized below:

Continued Planning to Include Consideration of Winter Reserve Margins

As the Company looks forward, the planning focus will include consideration of winter peak demand based upon resource adequacy study results. As additional summer-oriented resources such as solar are added to both the DEC and DEP systems, it will be important to maintain a focus on the impacts of these resources to the winter peak and the operational requirements of the system.

Continued Reliance on EE and DSM Resources

The Company is committed to continuing to grow the amount of EE and DSM resources utilized to meet customer growth. The following are the ways in which DEC will increase these resources:

- Continue to execute the Company's EE and DSM plan, which includes a diverse portfolio of EE and DSM programs spanning the residential, commercial, and industrial classes.
- Continue on-going collaborative work to develop and implement additional cost-effective EE and DSM products and services.
- Continue to seek enhancements to the Company's EE/DSM portfolio by: (1) adding new or expanding existing programs to include additional measures, (2) program modifications to account for changing market conditions and new measurement and verification (M&V) results and (3) other EE research & development pilots.
- Continue to seek additional DSM programs that will specifically benefit during winter peak situations.

Continued Focus on Renewable Energy Resources

DEC is committed to full compliance with NC REPS in North Carolina and is actively exploring incremental renewable resource additions contemplated under the recently passed South Carolina legislation. Due to Federal and State subsidies for solar developers, the Company is experiencing a substantial increase in solar QFs in the interconnection queue. With this level of interest in solar development, DEC continues to procure renewable purchase power resources, when economically viable, as part of its Compliance Plan. DEC is also pursuing the addition of new utility-owned solar on the DEC system.

In 2015, DEC received approval for SC DER which includes a portfolio of initiatives designed to increase the capacity of renewable generation located in South Carolina's service area. The program contains three tiers; each is equivalent to 1% of the Company's estimated average South Carolina retail peak demand (or 40 MW of nameplate solar capacity). The first tier of SC DER is comprised of a combination of utility scale PPAs and ~1 MW shared solar facilities. The second tier of SC DER is met via behind-the-meter net rooftop solar for residential, commercial, and industrial customers. Since tier 2 is behind the meter, the expected solar generation is embedded in the load forecast as a reduction to expected load. Upon completion of tiers 1 and 2 (to occur no later than 2021), the legislation calls for the utility to directly invest in additional solar generation to complete tier 3 which DEC contemplates doing in 2019.

DEC continues to evaluate market options for renewable generation and procure capacity, as appropriate. PPAs have been signed with developers of solar PV, landfill gas and wind resources. Also, REC purchase agreements have been executed for purchases of unbundled RECs from wind, solar PV, solar thermal and hydroelectric facilities. Additionally, shared solar programs and utility-owned solar continue to be considered.

Continue to Find Opportunities to Enhance Existing Clean Resources

DEC is committed to continually looking for opportunities to improve and enhance its existing resources. DEC has committed to the replacement of the runners on each of its four Bad Creek pumped storage units. Each replacement is expected to gain approximately 46 MW of capacity. The first replacement is projected to be in 2020, available for the 2021 winter peak. The remaining units will be replaced at the rate of one per year for availability in the winter peaks from 2022 – 2024.

Continue to Pursue New Nuclear

As part of the 2016 IRP, new nuclear resources continue to be supported in the resource plan in the 2024 to 2030 timeframe, depending on the scenario. Given the time it takes to receive a Combined Construction and Operating License from the Nuclear Regulatory Commission (NRC) and the significant reduction in lead time and risk to build a new nuclear facility with a COL in hand, Duke Energy views the receipt of a COL as a valuable asset for its customers.

DEC remains on course to obtain the COL for the Lee Nuclear facility in 2016. The following is a summary of the activities relative to the COL for the Lee Nuclear facility. There are three primary milestones that a project must complete to receive a COL: Final Environmental Impact Statement (FEIS), Final Safety Evaluation Report (FSER), and a Mandatory Hearing. On Dec. 23, 2013, the NRC issued the FEIS for Lee Nuclear, and on Jan. 2, 2014, the South Carolina Department of Health and Environmental Control (SC DHEC) issued the final Water Quality Certification. With the National Pollutant Discharge Elimination System (NPDES)[7] permit, which was issued in July 2013, all of the major, required environmental permits and certifications required for the COL have been received. The NRC issued the FSER on August 1, 2016 and the Mandatory Hearing for the Lee COL is scheduled for October 5, 2016. Receipt of the Lee COL is expected by December 2016. The schedule for receipt of the Lee COL supports the earliest projected need date for Lee Unit 1 in 2024 and Unit 2 in 2026.

Addition of Clean Natural Gas Resources

- Continue construction of the Lee combined cycle plant at the Lee Steam Station site located in Anderson, SC. As demonstrated in recent IRP plans, a capacity need was identified in 2017/2018 to allow DEC to meet its customers' load demands. After evaluating multiple bids in an RFP to address the 2017/2018 capacity need, the Company determined the most economical alternative to meet the need was to construct a new natural gas combined cycle facility at the Lee Steam Station site in Anderson County SC. The Company received a Certificate of Environmental Compatibility and Public Convenience and Necessity (CECPCN) in an order dated May 2, 2014, to move forward with the construction of the Lee CC.

- Lee Steam Station Unit 3 was converted from coal to clean-burning natural gas fuel in 2015.

Continued Focus on Environmental Compliance and Wholesale

- Retire older coal generation. As of April 2015, approximately 1,700 MW (winter/summer) of older coal generation has been retired and replaced with clean-burning natural gas, renewable energy resources or energy efficiency. The final older, un-

[7] The Section 402 NPDES permit and the Section 401 Water Quality Certification are part of the Clean Water Act.

scrubbed coal units at Lee Steam Station were retired in November 2014. Currently, Duke Energy Carolinas has no remaining older, un-scrubbed coal units in operation.[8]

- Continue to investigate the future environmental control requirements and resulting operational impacts associated with existing and potential environmental regulations such as EPA's Clean Power Plan (Section 111d of Clean Air Act regulating CO_2 from existing power plants), Mercury Air Toxics Standard (MATS), the Coal Combustion Residuals (CCR) rule, the Cross-State Air Pollution Rule (CSAPR), and the new ozone National Ambient Air Quality Standard (NAAQS).

- Continue to pursue existing and potential opportunities for wholesale power sales agreements within the Duke Energy balancing authority area.

- Continue to monitor energy-related statutory and regulatory activities.

- Continue to examine the benefits of joint capacity planning and pursue appropriate regulatory actions.

A summarization of the capacity resource changes for the Base Case in the 2016 IRP is shown in Table 9-A below. Capacity retirements and additions are presented as incremental values in the year in which the change impacts the winter peak. The values shown for renewable resources, EE and DSM represent cumulative totals.

---

[8] The ultimate timing of unit retirements can be influenced by factors changing the economics of continued unit operations. Such factors include changes in relative fuel prices, operations and maintenance costs and the costs associated with compliance of evolving environmental regulations. As such, unit retirement schedules are expected change over time as market conditions change.

Table 9-A DEC Short-Term Action Plan

Duke Energy Carolinas Short-Term Action Plan [1]						
			Compliance Renewable Resources (Cumulative Nameplate MW)			
Year	Retirements	Additions	Solar [2]	Biomass/Hydro	EE	DSM [3]
2017		25 MW Nuc	483	77	57	490
2018		683 MW Lee CC[4]	635	60	107	501
2019		10 MW Hydro Refurb[5]	751	53	148	513
2020		60 MW Nuc 6 MW Hydro Refurb[5]	887	52	191	526
2021		46 MW Bad Creek	1044	50	254	538

Notes:

(1) Capacities are shown in winter ratings unless otherwise noted.

(2) Capacity is shown in nameplate ratings. For planning purposes, solar presents a 5% contribution to peak.

(3) Includes impacts of grid modernization.

(4) 683 MW is net of NCEMC portion of Lee CC

(5) Rocky Creek is currently offline for refurbishment. Hydro Refurb MW in table represent expected return to service date.

DEC Request for Proposal (RFP) Activity

Supply-Side

No supply-side RFPs have been issued since the filing of DEC's 2015 IRP.

Renewable Energy

Duke Energy Distributed Energy Resource Solar RFP – South Carolina

A Shared Solar Program RFP was released on August 20, 2015, to solicit for up to 5 MW_{AC} (4 MW_{AC} in DEC/1 MW_{AC} in DEP) of solar PV facilities that would provide power and associated energy certificates within the DEC and DEP service territories in the state of South Carolina. Executed contracts in response to this RFP will be utilized to comply with the Duke Energy's "Shared Solar Program" under the South Carolina Distributed Energy Resource Program Act.

The RFP's interest was in solar PPAs and turnkey asset purchase proposals with a nameplate capacity sized > 250 kilowatts ($kW_{AC)}$ but no greater than 1 MW_{AC}. Proposals must be directly connected to the DEC or DEP transmission or distribution system in South Carolina. Projects must be in-service and capable of delivering fully rated output by December 31, 2016. PPA contract durations shall be a 10 year term.

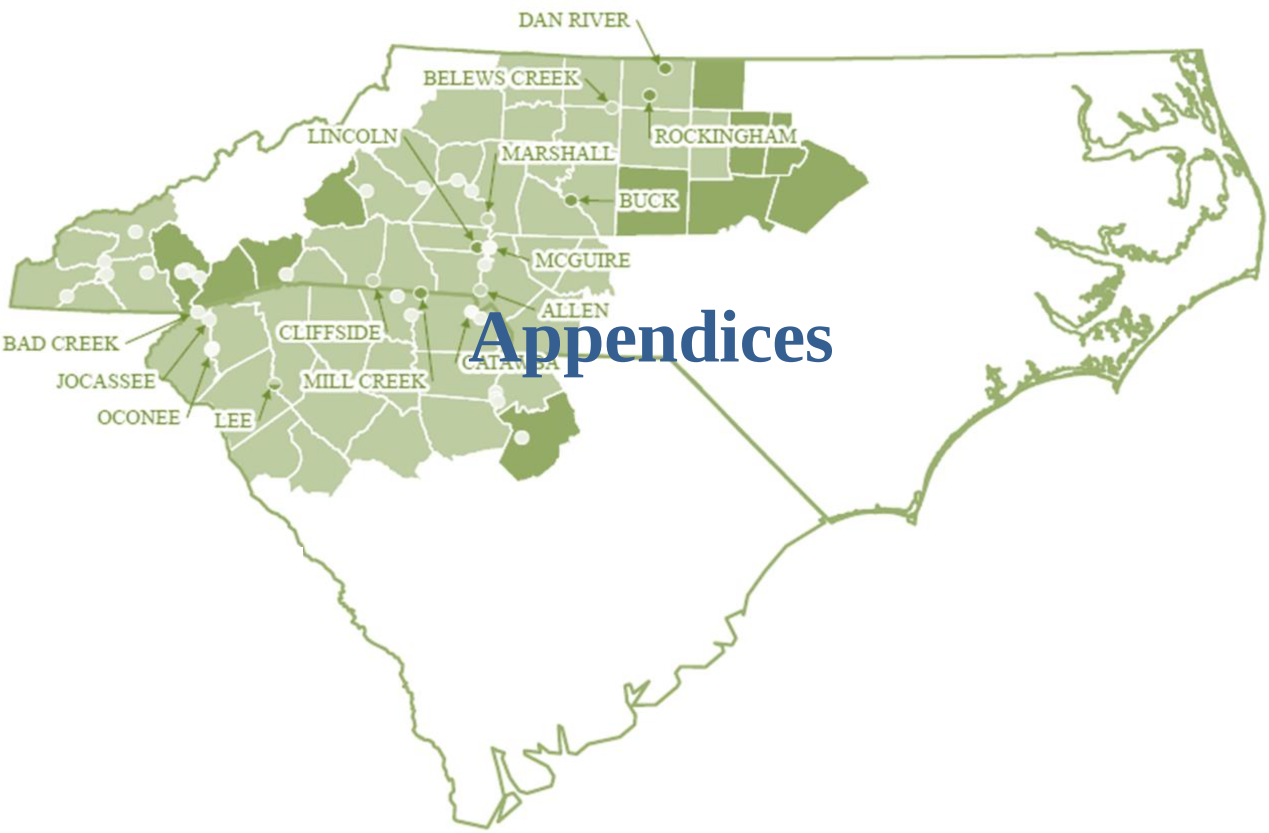
Respondents were notified, February 22, 2016 of their proposal status and if they had been selected as a proposal of interest.

Proposals of interest were allowed to refresh bid pricing following the completion of DEC/DEP estimated interconnection costs. Proposals of interest are currently in varying stages of negotiations and contract execution.

Duke Energy Carolinas – General Compliance RFP

Under this RFP, DEC will be soliciting proposals to procure renewable resources to meet the general compliance under the North Carolina Renewable Energy and Energy Efficiency Portfolio Standard (REPS) while expanding DECs emission free, diversified distributed generation portfolio. This RFP will seek up to 750,000 megawatt-hours (MWh) of energy and associated renewable energy certificates for projects that will achieve commercial operation within the 2017/2018 timeframe. Proposal structures allowed must be in the form of Purchased Power Agreements or Engineering, Procurement & Construction/Turnkey projects. All projects must be located in DEC's retail service territory in the state of North Carolina. There will be a preference for operational projects or projects in late stage of development.

DUKE ENERGY®
CAROLINAS



Appendices

APPENDICES TABLE OF CONTENTS:

SECTION: **PAGE:**

APPENDIX A: QUANTITATIVE ANALYSIS

This appendix provides an overview of the Company's quantitative analysis of the resource options available to meet customers' future energy needs. Sensitivities on major inputs resulted in multiple portfolios that were then evaluated under several scenarios that varied fuel prices, capital costs, and CO_2 constraints. These portfolios were analyzed using a least cost analysis to determine the Base Case for the 2016 IRP. The selection of this plan takes into account the cost to customers, resource diversity and reliability and the long-term carbon intensity of the system.

The future resource needs were optimized for DEC and DEP independently. However, an additional case representative of jointly planning future capacity on a DEC/DEP combined system basis using the Base Case assumptions was also analyzed to demonstrate potential customer savings, if this option was available in the future. Resource capacities discussed in this appendix reflect winter ratings and new resource additions are assumed online in January of the year indicated unless otherwise noted.

A. Overview of Analytical Process

The analytical process consists of four steps:

1. Assess resource needs
2. Identify and screen resource options for further consideration
3. Develop portfolio configurations
4. Perform portfolio analysis over various scenarios

1. Assess Resource Needs

The required load and generation resource balance needed to meet future customer demands was assessed as outlined below:

- Customer peak demand and energy load forecast – identified future customer aggregate demands to determine system peak demands and developed the corresponding energy load shape. Post-2020 consideration was also given to increased energy prices associated with a carbon constrained future.
- Existing supply-side resources – summarized each existing generation resource's operating characteristics including unit capability, potential operational constraints and life expectancy.

- Operating parameters – determined operational requirements including target planning reserve margins and other regulatory considerations.

Customer load growth, the expiration of purchased power contracts and additional asset retirements result in significant resource needs to meet energy and peak demands in the future. The following assumptions impacted the 2016 resource plan:

- Peak Demand and Energy Growth - The growth in winter customer peak demand including the impacts of energy efficiency averaged 1.3% from 2017 through 2031. The forecasted compound annual growth rate for energy consumption is 1.0% after the impacts of energy efficiency programs are included.
- Generation
    - Completion of the 683 MW Lee CC in November of 2017
    - Runner upgrades totaling 185 MW between 2020 and 2024 at Bad Creek Pumped-Storage Generating Station
    - Expected nuclear up-rates of 85 MW by 2020
- Retirements - Retirement of 604 MW at Allen Steam Station (Units 1 – 3) in December 2024 and the remaining 557 MW at Allen Steam Station in June 2028 (Units 4 and 5)
- Reserve Margin - A 17% minimum winter planning reserve margin for the planning horizon

2. Identify and Screen Resource Options for Further Consideration

The IRP process evaluated EE, DSM and traditional and non-traditional supply-side options to meet customer energy and capacity needs. The Company developed EE and DSM projections based on existing EE/DSM program experience, the most recent market potential study, input from its EE/DSM collaborative and cost-effectiveness screening for use in the IRP. Supply-side options reflect a diverse mix of technologies and fuel sources (gas, nuclear and renewable). Supply-side options are initially screened based on the following attributes:

- Technical feasibility and commercial availability in the marketplace
- Compliance with all Federal and State requirements
- Long-run reliability
- Reasonableness of cost parameters

The Company compared the capacity size options and operational capabilities of each technology, with the most cost-effective options of each being selected for inclusion in the portfolio analysis phase. An overview of resources screened on technical basis and a levelized economic basis is discussed in Appendix F.

Resource Options

Supply-Side

Based on the results of the screening analysis, the following technologies were included in the quantitative analysis as potential supply-side resource options to meet future capacity needs (winter ratings):

- Baseload – 2 x 1,117 MW Nuclear units (AP1000)
- Baseload – 1,221 MW – 2 x 1 Advanced Combined Cycle (Duct Fired)
- Baseload – 22 MW – Combined heat and power
- Peaking/Intermediate – 468 MW – 2 x 7FA.05 CTs
    - (Based upon the cost to construct 4 units, available for brownfield sites only)
- Peaking/Intermediate – 936 MW – 4 x 7FA.05 CTs
- Renewable – 5 MW – Solar PV

Energy Efficiency and Demand-Side Management

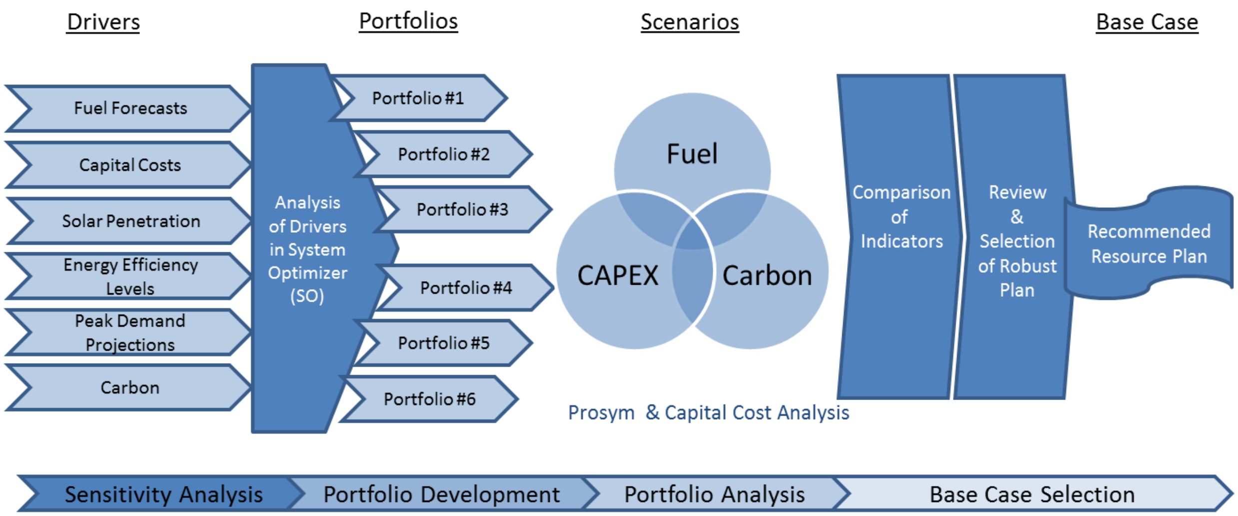
EE and DSM programs continue to be an important part of Duke Energy Carolinas' system mix. The Company considered both EE and DSM programs in the IRP analysis. As described in Appendix D, EE and DSM measures are compared to generation alternatives to identify cost-effective EE and DSM programs.

The Base Case EE/DSM savings contained in this IRP were projected by blending near-term program planning forecasts into the long-term achievable potential projections from the market potential study

3. Develop Portfolio Configurations

Once the load and generation balance was assessed, and resource options were screened, the portfolios and scenarios were developed, and the preferred Base Cases were selected, based on the following simplified diagram.

Figure A-1: Simplified Process Flow Diagram for Development and Selection of Base Case



The Company conducted a sensitivity analysis of various drivers using the simulation modeling software, *System Optimizer* (SO). The expansion plans produced by SO were compared and six portfolios that encompass the impact of the range of input sensitivities evaluated were identified[9]. An overview of the base planning assumptions and sensitivities considered is outlined below:

- Impact of potential carbon constraints
  - Portfolios were evaluated under scenarios that included the impacts of potential future carbon emission regulations. The final rule of the Clean Power Plan was published in the Federal Register October 23rd, 2015 which aim is to reduce CO_2 emissions from existing electric utility stationary sources. The Supreme Court granted a stay of this rule February 9th 2016 pending challenges from state and industry groups to the U.S. Court of Appeals for the D.C. Circuit. There is much uncertainty regarding the final outcome and timing of this rule but for the purposes of this IRP the CPP was used as a basis for evaluating potential impacts of carbon constraints. Two potential outcomes of the CPP were evaluated to provide guidance on the impact to existing, and potentially future units, over the planning horizon:

[9] An additional portfolio (No CO_2 constraints) was also developed, but was not evaluated as a potential Base Case portfolio through the Portfolio Analysis process.

  - Carbon Constraint #1: Carbon Tax – Incorporated an intrastate CO_2 tax starting in 2022 that was applied to existing coal and gas units.
  - Carbon Constraint #2: System Mass Cap – An alternate means of compliance for CPP in which total system CO_2 emissions were constrained starting in 2022 and declined until 2030. Total system emission were held flat from 2030 throughout the planning horizon.

- Retirements

  - Coal assets – For the purpose of this IRP, the depreciation book life was used as a placeholder for future retirement dates for coal assets, unless otherwise noted. Based on this assumption, Allen Steam Station Units 4 and 5 were retired in 2028. Allen Steam Station Units 1-3 were retired in 2024 based on the New Source Review (NSR) consent decree announced in September 2015.

  - Nuclear assets – Oconee Nuclear Station's current operating license has been extended to 60 years and expires in 2033. To date, no nuclear units in the United States have received a license extension beyond 60 years. For the purpose of this IRP, the Oconee Station is assumed to be retired in 2033.

    - A sensitivity was performed assuming an additional 20 year license renewal of existing nuclear units at the end of the current license life of 60 years.

- Coal and natural gas fuel prices

  - Short-term pricing: Natural gas prices were based on market observations from 2017 through 2026 transitioning to fundamental prices by 2032. Coal prices were based on market observations from 2017 through 2021 transitioning to fundamental prices by 2027.

  - Long-term pricing: Based on the Company's fundamental fuel price projections.

    - Sensitivities - A high fuel sensitivity was performed where the average Compound Annual Growth Rate (CAGR) for coal and gas was increased by 0.5% through 2035 and a low fuel sensitivity where the average CAGR for coal and gas was decreased by 1% CAGR through 2035.

- Capital Costs

  - All Assets (Nuclear, CC/CT, Renewables)

    - High Capital – Increased the inflation rate from 2.5% to 4%.

    - Low Capital – Decreased the inflation rate from 2.5% to 1%.

  - Renewables Only: Solar facility costs continue to decrease through 2020 with a 30% Federal ITC through 2019, 26% ITC in 2020, 22% ITC in 2021 and 10% ITC thereafter.

    - Low Cost - To determine if a lower cost would impacted the economic selection of additional solar resources, a capital cost sensitivity was performed where solar prices continue to decrease through 2025 with the same ITC assumptions as in the Base Case.

- Renewable Penetration

  - Base Penetration - Resources to comply with NC REPS along with solar customer product offerings such as Green Source and SC DER were input as existing resources. As described in Chapter 5, qualified facilities that the Company is required to purchase under PURPA and who do not sell renewable energy certificates to the Company are captured as non-compliance renewable purchases in the IRP as well. Below is an overview of the solar base planning assumptions and the sensitivities performed:

    - Higher Solar Penetration – To assess the impact if additional, non-compliance solar resources were installed on the system beyond the Base Case. The amount of base solar was increased by 789 MW by 2031.

    - Low Solar Penetration – To assess the potential impact of lower solar penetration levels due to lower fuel prices for more traditional generation technologies, higher solar installation and interconnection costs, lower avoided costs, and/or less favorable PURPA terms. The amount of base solar was decreased by 235 MW by 2031.

    - Under the System CO2 Mass Cap paradigm, additional economic solar was allowed to be selected up to 10% of the total system energy.

Incremental solar integration costs were added as a capital cost based on total solar added to the system *after* economic selection in SO.[10]

- Energy Efficiency

  - Base EE corresponds to the Company's current projections for achievable cost-effective EE program acceptance.

    - High EE – The high case EE/DSM savings included in the IRP modeling assumed a 50% increase in participation for the majority of the Base Case programs as further explained in Appendix C. By 2031, this accounts for an additional 262 MW reduction in total winter load.

- Nuclear Selection – Three different options were evaluated with regards to the selection of nuclear.

  - Carbon Tax - Lee Nuclear Station was assumed to be operational in November 2026 for Unit 1 and May 2028 for Unit 2. The model allowed additional nuclear units to be economically selected through 2061.

    - A sensitivity was performed without Lee Nuclear fixed in the plan.

  - System Mass Cap - Lee Nuclear Station was assumed to be operational in November 2026 for Unit 1 and May 2028 for Unit 2. The model allowed additional nuclear units to be economically selected through 2061.

    - A sensitivity was performed assuming a combination of higher penetration of solar (High Solar Penetration as described above) and a higher penetration of EE (High EE as described above). The purpose of the sensitivity was to determine the impact on additional economically selected nuclear generation after Lee Nuclear.

  - No CO_2 regulations – Lee Nuclear Station was assumed to be operational in November 2026 for Unit 1 and May 2028 for Unit 2.

    - A sensitivity was performed without Lee Nuclear fixed in the plan.

[10] Solar integration costs represented in the Duke Energy Photovoltaic Integration Study published by Pacific Northwest National Lab in March 2014.

- High and Low Load – Sensitivities were performed assuming changes in load of +6.5% starting in 2021 for High Load and – 6.5% for Low Load on average through 2031.

- A sensitivity was performed assuming joint planning with DEC and DEP to demonstrate the benefits of shared resources and how new generation could be delayed.

Results

A review of the results from the sensitivity analysis yielded some common themes.

Initial Resource Needs

The first two resource needs after the Lee CC Station with base EE and renewable assumptions are in 2023 and 2025. In the Carbon Tax paradigm, CC generation was selected optimally in 2023 and CT generation was selected in 2025. The CC continued to be selected in 2023 in the high fuel, high load, high capital, high EE and high renewable sensitivities. However in the low fuel and low capital sensitivities, CT generation was selected in 2023 and the CC generation was selected in 2025. Only in the load low and no CO_2 sensitivities was CC generation not selected in the 2023 to 2025 timeframe.

- One Balancing Authority - The first resource needs are CCs, one in DEP in 2022 and one in DEC in 2023. When planning as One Balancing Authority the DEC and DEP CCs are not delayed but the 2023 CT need in DEP and the 2025 CT need in DEC are delayed until 2026.

New Nuclear Selection – The Carbon Tax only applies to existing coal and gas generation and new nuclear does not have a carbon advantage over new CC generation. Without a carbon advantage new nuclear is not economically selected, however system carbon emissions continue to increase into the future. Lee Nuclear Station was input in November 2026 and May 2028 to provide an option for base load carbon free generation in the 2030 timeframe in the event of more stringent carbon regulation or in the event license extensions are not granted to existing nuclear generation. This is evident in the System Mass Cap constrained cases where Lee Nuclear and additional generic nuclear is needed in the 2032 timeframe to maintain flat CO_2 emissions after 2030. In the sensitivity with the inclusion of higher EE and higher renewables the additional generic nuclear is still needed in that timeframe.

Renewable Generation – In the cases developed under a Carbon Tax paradigm, no additional solar generation in excess of the base assumptions was selected. This was due in part to the significant level of solar already in the Base Case resource plan which reduces the value of incremental solar on the system. In the low cost solar sensitivity, where prices continued to decrease until 2026, additional economic solar was selected in several years beyond the study period. In the System Mass Cap paradigm additional economic solar was selected beginning in the early 2030s until 10% of the total energy was met with solar generation.

- *High Renewables* - A sensitivity was performed using the High Renewables case in the Carbon Tax paradigm. The inclusion of the increased implementation cost associated with high renewables resulted in a higher revenue requirement than the base expansion plan.

High EE – A sensitivity was performed using the High EE case in the Carbon Tax paradigm. Within the 15 year planning horizon the only change to the expansion plan was a delay in the 2025 CT need to 2026. The inclusion of the increased implementation cost associated with the high EE resulted in a higher revenue requirement than the base expansion plan.

High EE and Renewables – In the System Mass Cap paradigm a sensitivity was performed with a combination of High EE and Renewables to test the impact on new nuclear generation. Lee Nuclear was still needed by 2030 and additional generic nuclear generation was still required in the early to mid-2030's. The increased EE and Renewables did reduce the number of CCs required over the planning horizon.

Gas Firing Technology Options – In general, the first need was shown best met with CC generation, followed by CT generation through 2030. If Lee Nuclear Station is delayed additional CC generation would be selected in the 2025 timeframe.

Portfolio Development

Using insights gleaned from the sensitivity analysis, six portfolios were developed. These portfolios were developed in order to assess the relative value of various generating technologies including CCs, CTs, Renewables, and Nuclear, as well as, EE under multiple scenarios. Portfolios 1 – 4 were developed under a Carbon Tax paradigm where varying levels of an intrastate CO_2 tax were applied to existing coal and gas units as envisioned in EPA's CPP. Portfolios 5 and 6 were developed under a System CO_2 Mass Cap that represented an alternative outcome of the CPP. It should be noted that Portfolios 1 – 4 would not meet a CO_2 system mass cap. A description of the six portfolios follows:

Portfolio 1 (Base Case)

This portfolio represents the majority of expansions plans identified through the SO analysis. While CCs are the preferred initial generating option in both DEP and DEC, CTs make up the majority of additional resources added over the 15 year planning horizon. This portfolio also includes Lee Nuclear in November 2026 and May 2028, along with base EE and renewable assumptions.

Portfolio 2 (High Renewables, Lee Nuclear, Base EE)

This portfolio includes high renewables capacity through the planning period. In DEC, the high renewables assumption has the effect of delaying the first CT need by one year in the 15 year planning horizon. Beyond the 15 year horizon, additional CTs are delayed by one to two years with increased renewable capacity. This portfolio also includes Lee Nuclear in November 2026 and May 2028, along with base EE assumptions.

Portfolio 3 (High EE, Lee Nuclear, Base Renewables)

This portfolio includes high EE targets through the planning period. Similar to Portfolio #2, the high EE assumption has the effect of delaying the first CT need by one year in the 15 year planning horizon. Beyond the 15 year horizon, additional CTs are delayed by one to two years with increased EE targets. This portfolio also includes Lee Nuclear in November 2026 and May 2028, along with base renewable assumptions.

Portfolio 4 (CC Centric, No Lee Nuclear, Base EE/Renewables)

This portfolio replaces Lee Nuclear with two CCs; the first in November 2026 and the second in May 2028. This portfolio includes base renewable and base EE assumptions.

Portfolio 5 (System Mass Cap – Lee Nuclear + Additional nuclear generation, Base EE/Renewables)

This portfolio was developed under a System Mass Cap carbon constraint. This expansion plan is similar to Portfolio #1 through 2031, however from 2031 to 2040, one new nuclear plant replaces Oconee in DEC and one new nuclear plant is also required in DEP. Additionally, CT resources are replaced with CC resources in order to meet the carbon constraint. This portfolio includes base renewable and base EE assumptions plus additional economically selected solar in the 2030s.

Portfolio 6 (System Mass Cap – Lee Nuclear + Additional nuclear generation, High EE/Renewables)

Similar to Portfolio #5, this portfolio was developed under a System Mass Cap carbon constraint. This portfolio includes both high EE targets and high renewables assumptions.

Through 2031, this expansion plan converts the initial CC need to a CT need, and one new nuclear plant replaces Oconee in DEC and one new nuclear plant is also required in DEP in order to meet the carbon constraint. This portfolio also includes additional economically selected solar in the 2030s.

An overview of the resource needs of each portfolio are shown in Table A-1 below. The amount of solar in each portfolio is summarized in Table A-2.

Table A-1 DEC Portfolio Summary Plans

Year	Portfolio #1 (CT Centric)	Portfolio #2 (High Renewable)	Portfolio #3 (High EE)	Portfolio #4 (High CC)	Portfolio #5 (System Mass Cap)	Portfolio #6 (System Mass Cap - High EE / High Renewables)
2017						
2018						
2019						
2020						
2021						
2022	1123 MW CC	1123 MW CC	1123 MW CC	1123 MW CC	435 MW CT	435 MW CT
2023						
2024	435 MW CT			435 MW CT	1123 MW CC	870 MW CT
2025		435 MW CT	435 MW CT			
2026	1117 MW Lee Nuc 1	1117 MW Lee Nuc 1	1117 MW Lee Nuc 1	1123 MW CC	1117 MW Lee Nuc 1	1117 MW Lee Nuc 1
2027						
2028	1117 MW Lee Nuc 2	1117 MW Lee Nuc 2	1117 MW Lee Nuc 2	1123 MW CC	1117 MW Lee Nuc 2	1117 MW Lee Nuc 2
2029						
2030					500 Incremental Solar	
2031	435 MW CT	435 MW CT	435 MW CT	870 MW CT	435 MW CT 500 Incremental Solar	435 MW CT
2017 - 2031 Total	1123 MW CC 870 MW CT 1117 MW Lee Nuc 1 1117 MW Lee Nuc 2 0 Generic Nuclear 0 Incremental Solar	1123 MW CC 870 MW CT 1117 MW Lee Nuc 1 1117 MW Lee Nuc 2 0 Generic Nuclear 0 Incremental Solar	1123 MW CC 870 MW CT 1117 MW Lee Nuc 1 1117 MW Lee Nuc 2 0 Generic Nuclear 0 Incremental Solar	3369 MW CC 1305 MW CT 0 MW Lee Nuc 1 0 MW Lee Nuc 2 0 Generic Nuclear 0 Incremental Solar	1123 MW CC 870 MW CT 1117 MW Lee Nuc 1 1117 MW Lee Nuc 2 0 Generic Nuclear 1000 Incremental Solar	0 MW CC 1740 MW CT 1117 MW Lee Nuc 1 1117 MW Lee Nuc 2 0 Generic Nuclear 0 Incremental Solar

*Note: Timing for all resources in the above table are December 1st of the year indicated other than Lee Nuclear 1, which is assumed as November 2026, and Lee Nuclear 2, which is assumed as May 2028. Throughout the remainder of the document timing is based on units in service in January 1st of the year indicated.

Table A-2 DEC Cumulative Solar Summary (Nameplate MWs)

Year	Portfolio #1	Portfolio #2	Portfolio #3	Portfolio #4	Portfolio #5	Portfolio #6
2017	735	805	735	735	735	805
2018	907	1,057	907	907	907	1,057
2019	1,088	1,249	1,088	1,088	1,088	1,249
2020	1,244	1,436	1,244	1,244	1,244	1,436
2021	1,416	1,609	1,416	1,416	1,416	1,609
2022	1,542	1,810	1,542	1,542	1,542	1,810
2023	1,641	1,990	1,641	1,641	1,641	1,990
2024	1,724	2,140	1,724	1,724	1,724	2,140
2025	1,801	2,281	1,801	1,801	1,801	2,281
2026	1,873	2,413	1,873	1,873	1,873	2,413
2027	1,941	2,537	1,941	1,941	1,941	2,537
2028	2,004	2,654	2,004	2,004	2,004	2,654
2029	2,063	2,763	2,063	2,063	2,063	2,763
2030	2,118	2,864	2,118	2,118	2,618	2,864
2031	2,168	2,957	2,168	2,168	3,168	2,957

4. Perform Portfolio Analysis

The six portfolios identified in the screening analysis were evaluated in more detail with an hourly production cost model called PROSYM under several scenarios. The four scenarios are summarized in Table A-3 and included sensitivities on fuel, carbon, and capital cost.

Table A-3 Scenarios for Portfolio Analysis

	Carbon Tax/No Carbon Tax Scenarios[1]	Fuel	CO2	CAPEX
1	Current Trends	Base	CO2 Tax	Base
2	Economic Recession	Low Fuel	No CO2 Tax	Low
3	Economic Expansion	High Fuel	CO2 Tax	High

[1]Run Portfolios 1 - 4 through each of these 3 scenarios

	System Mass Cap Scenarios[2]	Fuel	CO2	CAPEX
4	Current Trends - CO_2 Mass Cap	Base	Mass Cap	Base

[2]Run Portfolios 5 - 6 through this single MC2 scenario

Portfolios 1 through 4 were analyzed under a current economic trend scenario (Scenario #1), an economic recession scenario (Scenario #2), and an economic expansion scenario (Scenario #3). Portfolios 5 & 6 were only evaluated under the Current Trends – CO_2 Mass Cap scenario (Scenario #4).

Under a System Mass Cap for carbon, fuel price and capital cost will have little impact on the optimization of the system as the carbon output of the various generators will control dispatch to a greater extent than the fuel price.

Portfolio 1 – 4 Analysis

Table A-4 below summarizes the PVRR of each portfolio compared to Portfolio #1 over the range of scenarios and sensitivities.

Table A-4 Delta PVRR for Portfolios #1 - #4 under Scenarios #1-#3

Delta PVRR 2016 - 2061, $Billions compared to Portfolio #1

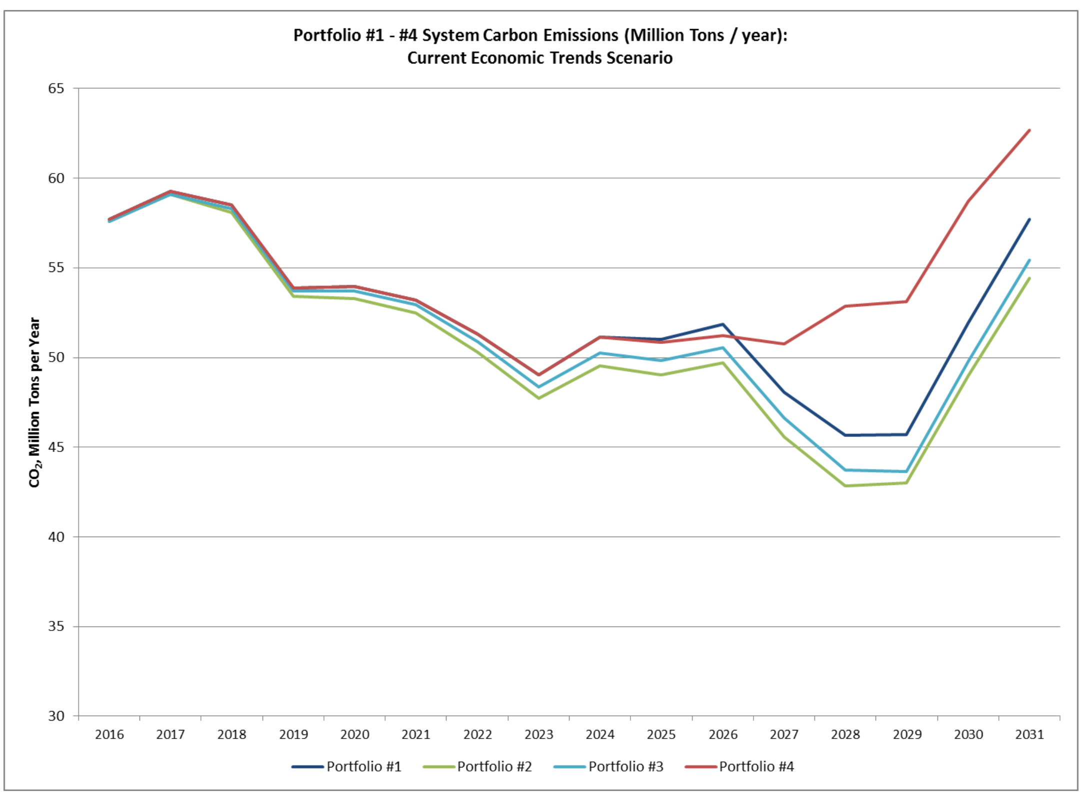
Portfolio	Scenario #1 (Current Trends)	Scenario #2 (Economic Recession)	Scenario #3 (Economic Expansion)
Portfolio #1 (Base Case)	$0	$0	$0
Portfolio #2 (High Renew)	$322	$464	$430
Portfolio #3 (High EE)	$69	$335	$22
Portfolio #4 (High CC)	-$4,992	-$6,077	-$6,212

*Note: Positive values indicate Portfolio #1 is a lower cost, Negative values indicate Portfolio #1 is a higher cost.

In the three scenarios, Portfolio #4 (CC Centric, No Lee Nuclear) was the lowest cost portfolio due to the absence of Lee Nuclear in the expansion plan. However, Portfolio #4 had the highest total system CO2 emissions of the four portfolios. In the portfolios that included the Lee Nuclear Plant, Portfolio #1 (Base Case) was the lowest cost portfolio. The costs of Portfolios 2 and 3 were negatively impacted by expanding the amount of renewable resources beyond the NC REPS requirements and energy efficiency above the Base Case assumptions. Portfolio #3 (High EE) had a PVRR that was nearly as low as Portfolio #1 when capital costs and fuel prices were increased in the Economic Expansion scenario. Portfolio #2 (High Renewables) had the lowest carbon footprint in each of the three scenarios evaluated.

Without the addition of new nuclear in the late 2020s, or relicensing or replacement of retiring nuclear units in the early 2030s, the CO_2 emissions increase significantly beginning in the 2028 timeframe. Figure A–2 illustrates this point by comparing the total cumulative DEC and DEP system CO_2 emissions of the Portfolios 1 - 4 through 2031 in the Current Trends scenario. To this point, when Robinson 2 is retired in 2030 in DEP, all Portfolios experience increased carbon emissions.

Figure A-2 Cumulative DEC & DEP System Carbon Emissions Summary for Portfolios 1-4 - Current Trends Scenario



Portfolio 5 and 6 Analysis

Table A-5 below summarizes the revenue requirements of Portfolios #5 and #6 under Scenario #4.

Table A-5 Delta PVRR for Portfolios #5 & #6 under Scenario #4

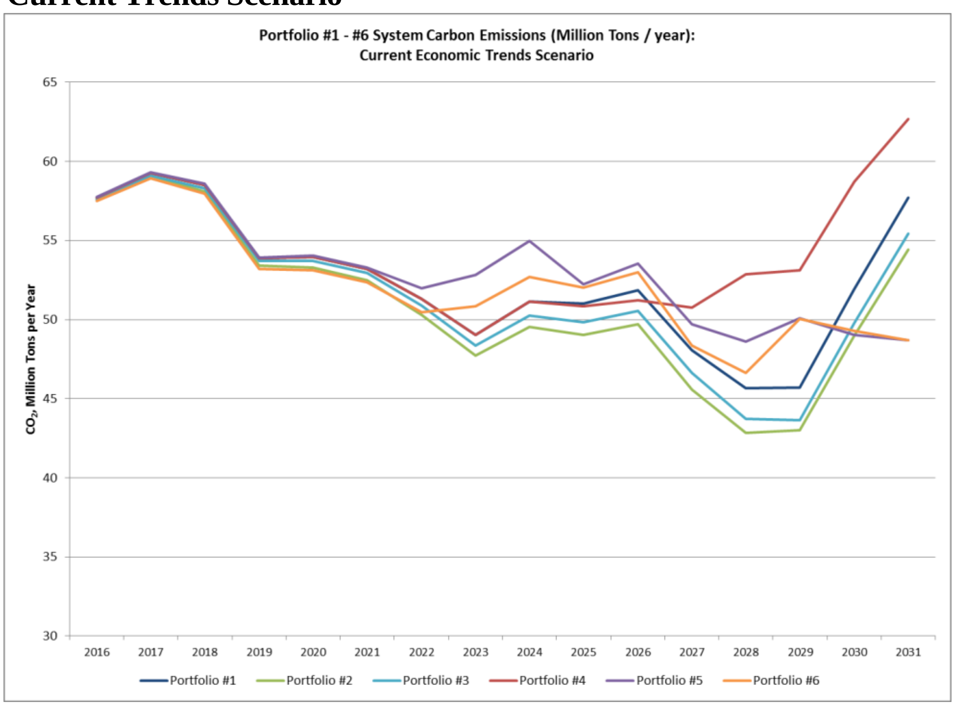
Delta PVRR 2016 - 2061, $Millions compared to Portfolio #5

Portfolio	Scenario #1 (Current Trends)
Portfolio #5 (System Mass Cap Base)	$0
Portfolio #6 (High EE / Renew)	$184

The high EE and high renewable combination led to a slightly higher PVRR versus the Base Case under a System Mass Cap carbon plan. The capital cost of the high EE/high renewable portfolio was nearly $1.9B higher than Portfolio #5, and this was mostly offset by approximately $1.7B in system production cost savings.

Cumulative DEC and DEP system carbon emissions for both Portfolio #5 and Portfolio #6 average less than 50 Million tons/year by the late-2020s and are projected to stay flat to declining beyond the study period as shown in Figure A-3.

Figure A-3 Cumulative DEC & DEP System Carbon Emissions Summary for Portfolios 1-6 – Current Trends Scenario



Conclusions

For planning purposes, Duke Energy considers the potential impact of a future where carbon emissions are constrained as the base plan. Portfolio #4 is the least cost portfolio from a revenue requirement basis in the Carbon Tax paradigm, however its carbon footprint would not be sustainable in the long term in a System CO_2 Mass Cap plan if new nuclear generation was not available in the late 2020s to early 2030s. Portfolios 1 through 3 add Lee Nuclear Station in the 2026-2028 timeframe which leads to a reduction in CO_2 emissions of about 15% to 20% by 2030. Portfolio #1 is the least cost portfolio with Lee Nuclear Station included, but none of these portfolios would meet a System CO_2 Mass Cap scenario unless existing nuclear generation was relicensed or replaced with new nuclear generation. By 2034, approximately 3,300 MW of existing nuclear generation will be retired in DEC and DEP unless their licenses can be extended. To date, no nuclear units in the United States have received a license extension beyond sixty years.

Duke Energy's current modeling practice uses a proxy CO_2 price forecast from a third party to simulate compliance where carbon emissions are constrained under the now stayed EPA Clean Power Plan. With the stay, the future of CO_2 legislation is still uncertain, and a system mass cap on carbon emissions is still a possibility. Portfolio #1 was chosen as the Base Case portfolio because the short term build plan would keep the Company on track if a System CO_2 Mass Cap were implemented, and it was the least cost portfolio with Lee Nuclear included from a revenue requirements perspective.

Value of Joint Planning

To demonstrate the value of sharing capacity with DEP, a Joint Planning Case was developed to examine the impact of joint capacity planning on the resource plans. The impacts were determined by comparing how the combined Base Cases of DEC and DEP would change if a 17% minimum winter planning reserve margin was applied at the combined system level, rather than the individual company level.

An evaluation was performed comparing the optimally selected Portfolio 1 for DEC and DEP to a combined Joint Planning Case in which existing and future capacity resources could be shared between DEC and DEP to meet the 17% minimum winter planning reserve margin. In this Joint Planning Case, sharing the Lee Nuclear Station on a load ratio basis with DEP was the most economic selection. Table A-4 shows the base expansion plans (Portfolio #1 for both DEC and DEP) through 2031, if separately planned, compared to the Joint Planning Case. The sum total of the two combined resource requirements is then compared to the amount of resources needed if DEC and DEP were able to jointly plan for capacity.

Table A-4 Comparison of Base Case Portfolio to Joint Planning Case

<table>
<tr><th></th><th>DEC</th><th>DEP</th><th>Joint Planning (1BA)</th></tr>
<tr><td>2021</td><td></td><td>1123 MW CC</td><td>1123 MW CC</td></tr>
<tr><td>2022</td><td>1123 MW CC</td><td>435 MW CT</td><td>1123 MW CC</td></tr>
<tr><td>2023</td><td></td><td></td><td></td></tr>
<tr><td>2024</td><td>435 MW CT</td><td></td><td></td></tr>
<tr><td>2025</td><td></td><td>435 MW CT</td><td>870 MW CT</td></tr>
<tr><td>2026</td><td>1117 MW Lee Nuc 1</td><td></td><td>1117 MW Lee Nuc 1</td></tr>
<tr><td>2027</td><td></td><td>435 MW CT</td><td>435 MW CT</td></tr>
<tr><td>2028</td><td>1117 MW Lee Nuc 2</td><td>435 MW CT</td><td>1117 MW Lee Nuc 2</td></tr>
<tr><td>2029</td><td></td><td></td><td></td></tr>
<tr><td>2030</td><td></td><td>1305 MW CT</td><td>1740 MW CT</td></tr>
<tr><td>2031</td><td>435 MW CT</td><td></td><td>1305 MW CT</td></tr>
<tr><td>2016 - 2031 Total</td><td>1123 MW CC
870 MW CT
1117 MW Lee Nuc 1
1117 MW Lee Nuc 2
0 Generic Nuclear
0 Incremental Solar</td><td>1123 MW CC
3045 MW CT
0 MW Lee Nuc 1
0 MW Lee Nuc 2
0 Generic Nuclear
0 Incremental Solar</td><td>2246 MW CC
4350 MW CT
1117 MW Lee Nuc 1
1117 MW Lee Nuc 2
0 Generic Nuclear
0 Incremental Solar</td></tr>
<tr><td>Average Winter Reserve Margin (2021 thru 2031)</td><td>19.4%</td><td>18.6%</td><td rowspan="2">18.4%</td></tr>
<tr><td>DEC / DEP Average Reserve Margin with Separate & Joint Planning (2021 thru 2031)</td><td colspan="2">19.0%</td></tr>
<tr><td>SO Calculated PVRR thru 2061, $B</td><td colspan="2">$124.2</td><td>$123.6</td></tr>
</table>

*Note: Timing for all resources in the above table are December 1st of the year indicated other than Lee Nuclear 1, which is assumed as November 2026, and Lee Nuclear 2, which is assumed as May 2028. Throughout the remainder of the document timing is based on units in service in January 1st of the year indicated.

A comparison of the DEC and DEP Combined Base Case resource requirements to the Joint Planning Scenario requirements illustrates the ability to defer CT resources over the 2016 to 2031 planning horizon. Consequently, the Joint Planning Case also results in a lower overall reserve margin. This is confirmed by a review of the reserve margins for the Combined Base Case as compared to the Joint Planning Case, which averaged 19.0% and 18.4%, respectively, from the first resource need in 2022 through 2031. The lower reserve margin in the Joint Planning Case indicates that DEC and DEP more efficiently and economically meet capacity needs when planning for capacity jointly. This is reflected in a total PVRR savings of $0.6 billion for the Joint Planning Case as compared to the Base Case.

B. Quantitative Analysis Summary

The quantitative analysis resulted in several key takeaways that are important for near-term decision-making, as well as in planning for the longer term.

1. The first undesignated resource need is in December of 2022 to meet the minimum reserve margin requirement in the winter of 2023. The results of this analysis show that this need is best met with CC generation.

2. The ability to jointly plan capacity with DEP provides customer savings by allowing for the deferral of new generation resources over the 2017 through 2031 planning horizon.

3. New nuclear generation is selected as an economic resource in a System CO2 Mass Cap future as identified in Portfolios 5 & 6. In the 15-year planning horizon, the addition of the Lee Nuclear Station in the 2026 to 2028 timeframe and two additional generic nuclear units, one in DEC and the other in DEP, were selected prior to 2040.

Portfolio 1 supports 100% ownership of Lee Nuclear Station by DEC. However, the Company continues to consider the benefits of regional nuclear generation. Sharing new baseload generation resources between multiple parties allows for resource additions to be better matched with load growth and for new construction risk to be shared among the parties. This results in positive benefits for the Company's customers. The benefits of co-ownership of the Lee Nuclear Station with DEP were also illustrated with the ability to jointly plan as represented in the Joint Planning Case.

APPENDIX B: DUKE ENERGY CAROLINAS OWNED GENERATION

Duke Energy Carolinas' generation portfolio includes a balanced mix of resources with different operating and fuel characteristics. This mix is designed to provide energy at the lowest reasonable cost to meet the Company's obligation to serve its customers. Duke Energy Carolinas-owned generation, as well as purchased power, is evaluated on a real-time basis in order to select and dispatch the lowest-cost resources to meet system load requirements. In 2015, Duke Energy Carolinas' nuclear, coal-fired and gas-fired generating units met the vast majority of customer needs by providing 61%, 27% and 11%, respectively, of Duke Energy Carolinas' energy from generation.Hydro-electric generation, solar generation, long term PPAs, and economical purchases from the wholesale market supplied the remainder.

The tables below list the Duke Energy Carolinas' plants in service in North Carolina (NC) and South Carolina (SC) with plant statistics, and the system's total generating capability.

Existing Generating Units and Ratings [a, b, c, d]
All Generating Unit Ratings are as of January 1, 2016

Coal						
	Unit	Winter (MW)	Summer (MW)	Location	Fuel Type	Resource Type
Allen	1	167	162	Belmont, N.C.	Coal	Peaking
Allen	2	167	162	Belmont, N.C.	Coal	Peaking
Allen	3	270	261	Belmont, N.C.	Coal	Peaking
Allen	4	282	276	Belmont, N.C.	Coal	Peaking
Allen	5	275	266	Belmont, N.C.	Coal	Peaking
Belews Creek	1	1110	1110	Belews Creek, N.C.	Coal	Base
Belews Creek	2	1110	1110	Belews Creek, N.C.	Coal	Base
Cliffside	5	556	552	Cliffside, N.C.	Coal	Peaking
Cliffside	6	844	844	Cliffside, N.C.	Coal	Intermediate
Marshall	1	380	380	Terrell, N.C.	Coal	Intermediate
Marshall	2	380	380	Terrell, N.C.	Coal	Intermediate
Marshall	3	658	658	Terrell, N.C.	Coal	Base
Marshall	4	660	660	Terrell, N.C.	Coal	Base
Total Coal		6859	6821			

Combustion Turbines						
	Unit	Winter (MW)	Summer (MW)	Location	Fuel Type	Resource Type
Lee	7C	41	41	Pelzer, S.C.	Natural Gas/Oil-Fired	Peaking
Lee	8C	41	41	Pelzer, S.C.	Natural Gas/Oil-Fired	Peaking
Lincoln	1	93	79.2	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking
Lincoln	2	93	79.2	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking
Lincoln	3	93	79.2	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking
Lincoln	4	93	79.2	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking
Lincoln	5	93	79.2	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking
Lincoln	6	93	79.2	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking
Lincoln	7	93	79.2	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking
Lincoln	8	93	79.2	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking
Lincoln	9	93	79.2	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking
Lincoln	10	93	79.2	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking
Lincoln	11	93	79.2	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking
Lincoln	12	93	79.2	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking
Lincoln	13	93	79.2	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking
Lincoln	14	93	79.2	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking
Lincoln	15	93	79.2	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking
Lincoln	16	93	79.2	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking
Mill Creek	1	92.4	74.42	Blacksburg, S.C.	Natural Gas/Oil-Fired	Peaking
Mill Creek	2	92.4	74.42	Blacksburg, S.C.	Natural Gas/Oil-Fired	Peaking
Mill Creek	3	92.4	74.42	Blacksburg, S.C.	Natural Gas/Oil-Fired	Peaking
Mill Creek	4	92.4	74.42	Blacksburg, S.C.	Natural Gas/Oil-Fired	Peaking
Mill Creek	5	92.4	74.42	Blacksburg, S.C.	Natural Gas/Oil-Fired	Peaking
Mill Creek	6	92.4	74.42	Blacksburg, S.C.	Natural Gas/Oil-Fired	Peaking
Mill Creek	7	92.4	74.42	Blacksburg, S.C.	Natural Gas/Oil-Fired	Peaking
Mill Creek	8	92.4	74.42	Blacksburg, S.C.	Natural Gas/Oil-Fired	Peaking
Rockingham	1	179	165	Rockingham, N.C.	Natural Gas/Oil-Fired	Peaking
Rockingham	2	179	165	Rockingham, N.C.	Natural Gas/Oil-Fired	Peaking
Rockingham	3	179	165	Rockingham, N.C.	Natural Gas/Oil-Fired	Peaking
Rockingham	4	179	165	Rockingham, N.C.	Natural Gas/Oil-Fired	Peaking
Rockingham	5	179	165	Rockingham, N.C.	Natural Gas/Oil-Fired	Peaking
Total NC		2,383	2,092			
Total SC		821	677			
Total CT		3,204	2,770			

Natural Gas Fired Boiler						
		Winter (MW)	Summer (MW)	Location	Fuel Type	Resource Type
Lee	3	170.0	170.0	Pelzer, N.C.	Nat. Gas	Peaking
Total Nat. Gas		170.0	170.0			

Combined Cycle						
	Unit	Winter (MW)	Summer (MW)	Location	Fuel Type	Resource Type
Buck	CT11	190.7	176.3	Salisbury, N.C.	Natural Gas	Base
Buck	CT12	189.8	175.1	Salisbury, N.C.	Natural Gas	Base
Buck	ST10	316.8	316.8	Salisbury, N.C.	Natural Gas	Base
Buck CTCC		697.3	668.2			
Dan River	CT8	193.0	165.0	Eden, N.C.	Natural Gas	Base
Dan River	CT9	193.0	166.0	Eden, N.C.	Natural Gas	Base
Dan River	ST7	320.0	320.0	Eden, N.C.	Natural Gas	Base
Dan River CTCC		706.0	651.0			
Total CTCC		1,403.3	1,319.2			

Pumped Storage						
	Unit	Winter (MW)	Summer (MW)	Location	Fuel Type	Resource Type
Jocassee	1	195	195	Salem, S.C.	Pumped Storage	Peaking
Jocassee	2	195	195	Salem, S.C.	Pumped Storage	Peaking
Jocassee	3	195	195	Salem, S.C.	Pumped Storage	Peaking
Jocassee	4	195	195	Salem, S.C.	Pumped Storage	Peaking
Bad Creek	1	340	340	Salem, S.C.	Pumped Storage	Peaking
Bad Creek	2	340	340	Salem, S.C.	Pumped Storage	Peaking
Bad Creek	3	340	340	Salem, S.C.	Pumped Storage	Peaking
Bad Creek	4	340	340	Salem, S.C.	Pumped Storage	Peaking
Total Pump Stor		2,140	2,140			

Hydro						
	Unit	Winter (MW)	Summer (MW)	Location	Fuel Type	Resource Type
99 Islands	1	2.4	2.4	Blacksburg, S.C.	Hydro	Peaking
99 Islands	2	2.4	2.4	Blacksburg, S.C.	Hydro	Peaking
99 Islands	3	2.4	2.4	Blacksburg, S.C.	Hydro	Peaking
99 Islands	4	2.4	2.4	Blacksburg, S.C.	Hydro	Peaking
99 Islands	5	0	0	Blacksburg, S.C.	Hydro	Peaking
99 Islands	6	0	0	Blacksburg, S.C.	Hydro	Peaking
Bear Creek	1	9.5	9.5	Tuckasegee, N.C.	Hydro	Peaking
Bridgewater	1	15	15	Morganton, N.C.	Hydro	Peaking
Bridgewater	2	15	15	Morganton, N.C.	Hydro	Peaking
Bridgewater	3	1.5	1.5	Morganton, N.C.	Hydro	Peaking
Bryson City	1	0	0	Whittier, N.C.	Hydro	Peaking
Bryson City	2	0	0	Whittier, N.C.	Hydro	Peaking
Cedar Cliff	1	6.4	6.4	Tuckasegee, N.C.	Hydro	Peaking
Cedar Cliff	2	0.4	0.4	Tuckasegee, N.C.	Hydro	Peaking
Cedar Creek	1	15	15	Great Falls, S.C.	Hydro	Peaking
Cedar Creek	2	15	15	Great Falls, S.C.	Hydro	Peaking
Cedar Creek	3	15	15	Great Falls, S.C.	Hydro	Peaking
Cowans Ford	1	81.3	81.3	Stanley, N.C.	Hydro	Peaking
Cowans Ford	2	81.3	81.3	Stanley, N.C.	Hydro	Peaking
Cowans Ford	3	81.3	81.3	Stanley, N.C.	Hydro	Peaking
Cowans Ford	4	81.3	81.3	Stanley, N.C.	Hydro	Peaking
Dearborn	1	14	14	Great Falls, S.C.	Hydro	Peaking
Dearborn	2	14	14	Great Falls, S.C.	Hydro	Peaking
Dearborn	3	14	14	Great Falls, S.C.	Hydro	Peaking
Fishing Creek	1	11	11	Great Falls, S.C.	Hydro	Peaking
Fishing Creek	2	9.5	9.5	Great Falls, S.C.	Hydro	Peaking
Fishing Creek	3	9.5	9.5	Great Falls, S.C.	Hydro	Peaking
Fishing Creek	4	11	11	Great Falls, S.C.	Hydro	Peaking
Fishing Creek	5	8	8	Great Falls, S.C.	Hydro	Peaking
Franklin	1	0.5	0.5	Franklin, N.C.	Hydro	Peaking
Franklin	2	0.5	0.5	Franklin, N.C.	Hydro	Peaking
Gaston Shoals	3	0	0	Blacksburg, S.C.	Hydro	Peaking
Gaston Shoals	4	1	1	Blacksburg, S.C.	Hydro	Peaking
Gaston Shoals	5	1	1	Blacksburg, S.C.	Hydro	Peaking
Gaston Shoals	6	0	0	Blacksburg, S.C.	Hydro	Peaking

Hydro cont.						
	Unit	Winter (MW)	Summer (MW)	Location	Fuel Type	Resource Type
Great Falls	1	3	3	Great Falls, S.C.	Hydro	Peaking
Great Falls	2	3	3	Great Falls, S.C.	Hydro	Peaking
Great Falls	3	0	0	Great Falls, S.C.	Hydro	Peaking
Great Falls	4	0	0	Great Falls, S.C.	Hydro	Peaking
Great Falls	5	3	3	Great Falls, S.C.	Hydro	Peaking
Great Falls	6	3	3	Great Falls, S.C.	Hydro	Peaking
Great Falls	7	0	0	Great Falls, S.C.	Hydro	Peaking
Great Falls	8	0	0	Great Falls, S.C.	Hydro	Peaking
Keowee	1	76	76	Seneca, S.C.	Hydro	Peaking
Keowee	2	76	76	Seneca, S.C.	Hydro	Peaking
Lookout Shoals	1	9.3	9.3	Statesville, N.C.	Hydro	Peaking
Lookout Shoals	2	9.3	9.3	Statesville, N.C.	Hydro	Peaking
Lookout Shoals	3	9.3	9.3	Statesville, N.C.	Hydro	Peaking
Mission	1	0.6	0.6	Murphy, N.C.	Hydro	Peaking
Mission	2	0.6	0.6	Murphy, N.C.	Hydro	Peaking
Mission	3	0	0	Murphy, N.C.	Hydro	Peaking
Mountain Island	1	14	14	Mount Holly, N.C.	Hydro	Peaking
Mountain Island	2	14	14	Mount Holly, N.C.	Hydro	Peaking
Mountain Island	3	17	17	Mount Holly, N.C.	Hydro	Peaking
Mountain Island	4	17	17	Mount Holly, N.C.	Hydro	Peaking
Nantahala	1	50	50	Topton, N.C.	Hydro	Peaking
Oxford	1	20	20	Conover, N.C.	Hydro	Peaking
Oxford	2	20	20	Conover, N.C.	Hydro	Peaking
Queens Creek	1	1.4	1.4	Topton, N.C.	Hydro	Peaking
Rhodhiss	1	9.5	9.5	Rhodhiss, N.C.	Hydro	Peaking
Rhodhiss	2	11.5	11.5	Rhodhiss, N.C.	Hydro	Peaking
Rhodhiss	3	12.4	12.4	Rhodhiss, N.C.	Hydro	Peaking
Rocky Creek	1	0	0	Great Falls, S.C.	Hydro	Peaking
Rocky Creek	2	0	0	Great Falls, S.C.	Hydro	Peaking
Rocky Creek	3	0	0	Great Falls, S.C.	Hydro	Peaking
Rocky Creek	4	0	0	Great Falls, S.C.	Hydro	Peaking

Hydro cont.						
	Unit	Winter (MW)	Summer (MW)	Location	Fuel Type	Resource Type
Rocky Creek	5	0	0	Great Falls, S.C.	Hydro	Peaking
Rocky Creek	6	0	0	Great Falls, S.C.	Hydro	Peaking
Rocky Creek	7	0	0	Great Falls, S.C.	Hydro	Peaking
Rocky Creek	8	0	0	Great Falls, S.C.	Hydro	Peaking
Tuxedo	1	3.2	3.2	Flat Rock, N.C.	Hydro	Peaking
Tuxedo	2	3.2	3.2	Flat Rock, N.C.	Hydro	Peaking
Tennessee Creek	1	9.8	9.8	Tuckasegee, N.C.	Hydro	Peaking
Thorpe	1	19.7	19.7	Tuckasegee, N.C.	Hydro	Peaking
Tuckasegee	1	2.5	2.5	Tuckasegee, N.C.	Hydro	Peaking
Wateree	1	17	17	Ridgeway, S.C.	Hydro	Peaking
Wateree	2	17	17	Ridgeway, S.C.	Hydro	Peaking
Wateree	3	17	17	Ridgeway, S.C.	Hydro	Peaking
Wateree	4	17	17	Ridgeway, S.C.	Hydro	Peaking
Wateree	5	17	17	Ridgeway, S.C.	Hydro	Peaking
Wylie	1	18	18	Fort Mill, S.C.	Hydro	Peaking
Wylie	2	18	18	Fort Mill, S.C.	Hydro	Peaking
Wylie	3	18	18	Fort Mill, S.C.	Hydro	Peaking
Wylie	4	18	18	Fort Mill, S.C.	Hydro	Peaking
Total NC		628.3	628.3			
Total SC		468.6	468.6			
Total Hydro		1,096.9	1,096.9			

Solar						
		Winter (MW)	Summer (MW)	Location	Fuel Type	Resource Type
NC Solar		3.87	3.87	N.C.	Solar	Intermittent
Total Solar		3.87	3.87			

Nuclear						
	Unit	Winter (MW)	Summer (MW)	Location	Fuel Type	Resource Type
McGuire	1	1199.0	1158.0	Huntersville, N.C.	Nuclear	Base
McGuire	2	1187.2	1157.6	Huntersville, N.C.	Nuclear	Base
Catawba	1	1173.7	1140.1	York, S.C.	Nuclear	Base
Catawba	2	1179.8	1150.1	York, S.C.	Nuclear	Base
Oconee	1	865	847	Seneca, S.C.	Nuclear	Base
Oconee	2	872	848	Seneca, S.C.	Nuclear	Base
Oconee	3	881	859	Seneca, S.C.	Nuclear	Base
Total NC		2,386.2	2,315.6			
Total SC		4,971.5	4,844.2			
Total Nuclear		7,357.7	7,159.8			

Total Generation Capability		
	Winter Capacity (MW)	Summer Capacity (MW)
TOTAL DEC SYSTEM - N.C.	13,664	13,180
TOTAL DEC SYSTEM – S.C.	8,571	8,300
TOTAL DEC SYSTEM	22,235	21,480

Note a: Unit information is provided by State, but resources are dispatched on a system-wide basis.

Note b: Summer and winter capability does not take into account reductions due to future environmental emission controls.

Note c: Catawba Units 1 and 2 capacity reflects 100% of the station's capability, and does not factor in NCMPA#1's decision to sell or utilize its 832 MW retained ownership in Catawba.

Note d: The Catawba units' multiple owners and their effective ownership percentages are:

Catawba Owner	Percent Of Ownership
Duke Energy Carolinas	19.246%
North Carolina Electric Membership Corporation (NCEMC)	30.754%
NCMPA#1	37.5%
PMPA	12.5%

Planned Uprates			
Unit	Date	Winter MW	Summer MW
Catawba 1[a,b]	June 2016	25	20
Oconee 1[b]	March 2019	20	15
Oconee 2[b]	March 2019	20	15
Oconee 3[b]	March 2019	20	15

Note a: The capacity represented in this table is the total operating capacity addition and is not adjusted for the Joint Exchange Agreement for Catawba and McGuire. The adjusted values are utilized in the resource plan.

Note b: Capacity not reflected in Existing Generating Units and Ratings section.

Planned Additions			
Unit	Date	Winter MW	Summer MW
Lee CC[a]	Nov 2017	783	753
Bad Creek 1[c]	June 2023	46.4	46.4
Bad Creek 2[c]	June 2020	46.4	46.4
Bad Creek 3[c]	June 2021	46.4	46.4
Bad Creek 4[c]	June 2022	46.4	46.4
Gaston Shoals 6[b]	8/1/2016	1.7	1.7
Mission 3[b]	7/1/2016	.6	.6
Bryson City 1[b]	5/1/2016	.5	.5
Bryson City 2[b]	5/1/2016	.5	.5

Note a: Includes 100 MW ownership by NCEMC.
Note b: Units expected to return to service.
Note c: Order of Bad Creek uprates subject to change.

Retirements				
Unit & Plant Name	Location	Capacity (MW) Winter / Summer	Fuel Type	Retirement Date
Buck 3 [a]	Salisbury, N.C.	76/75	Coal	05/15/11
Buck 4 [a]	Salisbury, N.C.	39/38	Coal	05/15/11
Cliffside 1 [a]	Cliffside, N.C.	39/38	Coal	10/1/11
Cliffside 2 [a]	Cliffside, N.C.	39/38	Coal	10/1/11
Cliffside 3 [a]	Cliffside, N.C.	62/61	Coal	10/1/11
Cliffside 4 [a]	Cliffside, N.C.	62/61	Coal	10/1/11
Dan River 1 [a]	Eden, N.C.	69/67	Coal	04/1/12
Dan River 2 [a]	Eden, N.C.	69/67	Coal	04/1/12
Dan River 3 [a]	Eden, N.C.	145/142	Coal	04/1/12
Buzzard Roost 6C [b]	Chappels, S.C.	20/20	Combustion Turbine	10/1/12
Buzzard Roost 7C [b]	Chappels, S.C.	20/20	Combustion Turbine	10/1/12
Buzzard Roost 8C	Chappels, S.C.	20/20	Combustion Turbine	10/1/12
Buzzard Roost 9C [b]	Chappels, S.C.	20/20	Combustion Turbine	10/1/12
Buzzard Roost 10C [b]	Chappels, S.C.	16/16	Combustion Turbine	10/1/12
Buzzard Roost 11C [b]	Chappels, S.C.	16/16	Combustion Turbine	10/1/12
Buzzard Roost 12C [b]	Chappels, S.C.	16/16	Combustion Turbine	10/1/12
Buzzard Roost 13C [b]	Chappels, S.C.	16/16	Combustion Turbine	10/1/12
Buzzard Roost 14C [b]	Chappels, S.C.	16/16	Combustion Turbine	10/1/12
Buzzard Roost 15C [b]	Chappels, S.C.	16/16	Combustion Turbine	10/1/12
Riverbend 8C [b]	Mt. Holly, N.C.	20/20	Combustion Turbine	10/1/12
Riverbend 9C [b]	Mt. Holly, N.C.	30/22	Combustion Turbine	10/1/12
Riverbend 10C [b]	Mt. Holly, N.C.	30/22	Combustion Turbine	10/1/12
Riverbend 11C [b]	Mt. Holly, N.C.	30/20	Combustion Turbine	10/1/12
Buck 7C [b]	Spencer, N.C.	30/25	Combustion Turbine	10/1/12
Buck 8C [b]	Spencer, N.C.	30/25	Combustion Turbine	10/1/12
Buck 9C [b]	Spencer, N.C.	16/12	Combustion Turbine	10/1/12
Dan River 4C [b]	Eden, N.C.	31/24	Combustion Turbine	10/1/12
Dan River 5C [b]	Eden, N.C.	31/24	Combustion Turbine	10/1/12
Dan River 6C [b]	Eden, N.C.	31/24	Combustion Turbine	10/1/12
Riverbend 4 [a]	Mt. Holly, N.C.	96/94	Coal	04/1/13
Riverbend 5 [a]	Mt. Holly, N.C.	96/94	Coal	04/1/13
Riverbend 6 [c]	Mt. Holly, N.C.	136/133	Coal	04/1/13
Riverbend 7 [c]	Mt. Holly, N.C.	136/133	Coal	04/1/13
Buck 5 [c]	Spencer, N.C.	131/128	Coal	04/1/13
Buck 6 [c]	Spencer, N.C.	131/128	Coal	04/1/13
Lee 1 [d]	Pelzer, S.C.	100/100	Coal	11/6/14
Lee 2 [d]	Pelzer, S.C.	102/100	Coal	11/6/14
Lee 3 [e]	Pelzer, S.C.	173/170	Coal	05/12/15*
	Total	2,156 MW / 2,037 MW		

Note a: Retirement assumptions associated with the conditions in the NCUC Order in Docket No. E-7, Sub 790, granting a CPCN to build Cliffside Unit 6.

Note b: The old fleet combustion turbines retirement dates were accelerated in 2009 based on derates, availability of replacement parts and the general condition of the remaining units.

Note c: The decision was made to retire Buck 5 & 6 and Riverbend 6 & 7 early on April 1, 2013. The original expected retirement date was April 15, 2015.

Note d: Lee Steam Units 1 and 2 were retired November 6, 2014.

Note e: The conversion of the Lee 3 coal unit to a natural gas unit was effective March 12, 2015.

Planning Assumptions – Unit Retirements					
Unit & Plant Name	Location	Winter Capacity (MW)	Summer Capacity (MW)	Fuel Type	Expected Retirement
Allen 1[a]	Belmont, NC	167	162	Coal	12/2024
Allen 2[a]	Belmont, NC	167	162	Coal	12/2024
Allen 3[a]	Belmont, NC	270	261	Coal	12/2024
Allen 4[a]	Belmont, NC	282	276	Coal	6/2028
Allen 5[a]	Belmont, NC	275	266	Coal	6/2028
Oconee 1[b,c]	Seneca, SC	865	847	Nuclear	5/2033
Oconee 2[b,c]	Seneca, SC	872	848	Nuclear	5/2033
Oconee 3[b,c]	Seneca, SC	881	859	Nuclear	5/2033
Total		3,779	3,681		

Note a: Retirement assumptions are for planning purposes only; dates are based on useful life expectations of the unit.

Note b: Nuclear retirements for planning purposes are based on the end of current operating license.

Note c: Oconee capacity includes scheduled uprates (15 MW/unit).

Operating License Renewal

Operating License Renewal				
Plant & Unit Name	Location	Original Operating License Expiration	Date of Approval	Operating License Expiration
Catawba Unit 1	York, SC	12/6/2024	12/5/2003	12/5/2043
Catawba Unit 2	York, SC	2/24/2026	12/5/2003	12/5/2043
McGuire Unit 1	Huntersville, NC	6/12/2021	12/5/2003	6/12/2041
McGuire Unit 2	Huntersville, NC	3/3/2023	12/5/2003	3/3/2043
Oconee Unit 1	Seneca, SC	2/6/2013	5/23/2000	2/6/2033
Oconee Unit 2	Seneca, SC	10/6/2013	5/23/2000	10/6/2033
Oconee Unit 3	Seneca, SC	7/19/2014	5/23/2000	7/19/2034
Bad Creek (PS)(1-4)	Salem, SC	N/A	8/1/1977	7//31/2027
Jocassee (PS) (1-4)	Salem, SC	N/A	9/1/2016	8/31/2046
Cowans Ford (1-4)	Stanley, NC	8/31/2008	11/1/2015	10/31/2055
Keowee (1&2)	Seneca, SC	N/A	9/1/2016	8/31/2046
Rhodhiss (1-3)	Rhodhiss, NC	8/31/2008	11/1/2015	10/31/2055
Bridge Water (1-3)	Morganton, NC	8/31/2008	11/1/2015	10/31/2055
Oxford (1&2)	Conover, NC	8/31/2008	11/1/2015	10/31/2055
Lookout Shoals (1-3)	Statesville, NC	8/31/2008	11/1/2015	10/31/2055
Mountain Island (1-4)	Mount Holly, NC	8/31/2008	11/1/2015	10/31/2055
Wylie (1-4)	Fort Mill, SC	8/31/2008	11/1/2015	10/31/2055
Fishing Creek (1-5)	Great Falls, SC	8/31/2008	11/1/2015	10/31/2055
Great Falls (1-8)	Great Falls, SC	8/31/2008	11/1/2015	10/31/2055
Dearborn (1-3)	Great Falls, SC	8/31/2008	11/1/2015	10/31/2055
Rocky Creek (1-8)	Great Falls, SC	8/31/2008	11/1/2015	10/31/2055
Cedar Creek (1-3)	Great Falls, SC	8/31/2008	11/1/2015	10/31/2055
Wateree (1-5)	Ridgeway, SC	8/31/2008	11/1/2015	10/31/2055
Gaston Shoals (3-6)	Blacksburg, SC	12/31/1993	6/1/1996	5/31/2036
Tuxedo (1&2)	Flat Rock, NC	N/A	N/A	N/A
Ninety Nine (1-6)	Blacksburg, SC	12/31/1993	6/1/1996	5/31/2036
Cedar Cliff (1)	Tuckasegee, NC	1/31/2006	5/1/2011	4/30/2041
Bear Creek (1)	Tuckasegee, NC	1/31/2006	5/1/2011	4/30/2041
Tennessee Creek (1)	Tuckasegee, NC	1/31/2006	5/1/2011	4/30/2041
Nantahala (1)	Topton, NC	2/28/2006	2/1/2012	1/31/2042

Planned Operating License Renewal cont.				
Plant & Unit Name	Location	Original Operating License Expiration	Date of Approval	Extended Operating License Expiration
Queens Creek (1)	Topton, NC	9/30/2001	3/1/2002	2/29/2032
Thorpe (1)	Tuckasegee, NC	1/31/2006	5/1/2011	4/30/2041
Tuckasegee (1)	Tuckasegee, NC	1/31/2006	5/1/2011	4/30/2041
Bryson City (1&2)	Whittier, NC	7/31/2005	7/1/2011	6/30/2041
Franklin (1&2)	Franklin, NC	7/31/2005	9/1/2011	8/31/2041
Mission (1-3)	Murphy, NC	7/31/2005	10/1/2011	9/30/2041

APPENDIX C: ELECTRIC LOAD FORECAST

Methodology

The Duke Energy Carolinas' Spring 2016 Forecast provides projections of the energy and peak demand needs for its service area. The forecast covers the time period of 2017 – 2031 and represent the needs of the following customer classes:

- Residential
- Commercial
- Industrial
- Other Retail
- Wholesale

Energy projections are developed with econometric models using key economic factors such as income, electricity prices, industrial production indices, along with weather, appliance efficiency trends, rooftop solar trends, and electric vehicle trends. Population is also used in the Residential customer model. DEC has used regression analysis since 1979 and this technique has yielded consistently reasonable results over the years.

The economic projections used in the Spring 2016 Forecast are obtained from Moody's Analytics, a nationally recognized economic forecasting firm, and include economic forecasts for the states of North Carolina and South Carolina.

The Retail forecast consists of the three major classes: Residential, Commercial and Industrial.

The Residential class sales forecast is comprised of two projections. The first is the number of residential customers, which is driven by population. The second is energy usage per customer, which is driven by weather, regional economic and demographic trends, electric price and appliance efficiencies.

The usage per customer forecast was derived using a Statistical Adjusted End-Use Model. This is a regression based framework that uses projected appliance saturation and efficiency trends developed by Itron using EIA data. It incorporates naturally occurring efficiency trends and government mandates more explicitly than other models. The outlook for usage per customer is slightly negative to flat through much of the forecast horizon, so most of the growth is primarily due to customer increases. The projected growth rate of Residential in the Spring 2016 Forecast after all adjustments for Utility Energy Efficiency programs, Solar and Electric Vehicles from 2017-2031 is 1.2%.

The Commercial forecast also uses an SAE model in an effort to reflect naturally occurring as well as government mandated efficiency changes. The three largest sectors in the Commercial class are Offices, Education and Retail. Commercial is expected to be the fastest growing Class, with a projected growth rate of 1.3%, after all adjustments.

The Industrial class is forecasted by a standard econometric model, with drivers such as total manufacturing output, textile output, and the price of electricity. Overall, Industrial sales are expected to grow 0.9% over the forecast horizon, after all adjustments.

County population projections are obtained from the North Carolina Office of State Budget and Management as well as the South Carolina Budget and Control Board. These are then used to derive the total population forecast for the 51 counties that comprise the DEC service area.

Weather impacts are incorporated into the models by using Heating Degree Days and Cooling Degree Days with a base temperature of 65. The forecast of degree days is based on a 30-year average, which is updated every year.

The appliance saturation and efficiency rends are developed by Itron using data from the EIA. Itron is a recognized firm providing forecasting services to the electric utility industry. These appliance trends are used in the residential and commercial sales models.

Peak demands were projected using the SAE approach in the Spring 2016 Forecast. The peak forecast was developed using a monthly SAE model, similar to the sales SAE models, which includes monthly appliance saturations and efficiencies, interacted with weather and the fraction of each appliance type that is in use at the time of monthly peak.

Assumptions

Below are the projected average annual growth rates of several key drivers from DEC's Spring 2016 Forecast.

	2017-2031
Real Income	2.9%
Mfg. IPI	1.8%
Population	1.0%

In addition to economic, demographic, and efficiency trends, the forecast also incorporates the expected impacts of UEE, as well as projected effects of electric vehicles and behind the meter solar technology.

Wholesale

For a description of the Wholesale forecast, please see Appendix H.

Historical Values

It should be noted that long-term structurally decline of the Textile industry and the recession of 2008-2009 have had an adverse impact on DEC sales. The worst of the Textile decline appears to be over, and Moody's Analytics expects the Carolina's economy to show solid growth going forward.

In tables C-1 and C-2 below the history of DEC customers and sales are given. As a note, the values in Table C-2 are not weather adjusted.

Table C-1 Retail Customers (Thousands, Annual Average)

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Residential	1,877	1,916	2,012	2,024	2,034	2,041	2,053	2,068	2,089	2,117
Commercial	317	322	334	331	333	335	337	339	342	345
Industrial	7	7	7	7	7	7	7	7	7	6
Other	13	13	14	14	14	14	14	14	15	15
Total	2,214	2,259	2,367	2,377	2,389	2,397	2,411	2,428	2,452	2,452

Table C-2 Electricity Sales (GWh Sold - Years Ended December 31)

	2007	2008	2009	2010	2011	2012	2013	2014	2015
Residential	27,459	27,335	27,273	30,049	28,323	26,279	26,895	27,976	27,916
Commercial	27,433	27,288	26,977	27,968	27,593	27,476	27,765	28,421	28,700
Industrial	23,948	22,634	19,204	20,618	20,783	20,978	21,070	21,577	22,136
Other	278	284	287	287	287	290	293	303	305
Total Retail	79,118	77,541	73,741	78,922	76,985	75,022	78,035	78,278	79,057
Wholesale	2,454	3,525	3,788	5,166	4,866	5,176	5,824	6,559	6,560
Total System	81,572	81,066	77,528	84,088	81,851	80,199	83,859	84,837	85,617

Utility Energy Efficiency

A new process for reflecting the impacts of UEE on the forecast was introduced in Spring 2015. The Spring 2016 Forecast continued this process. The concept of 'Measure Life' for a program was included in the calculations. For example, if the accelerated benefit of a residential UEE program is expected to have occurred 8 years before the energy reduction program would have been otherwise adopted, then the UEE effects after year 8 are subtracted ("rolled off") from the total cumulative UEE. With the SAE models framework, the naturally occurring appliance efficiency trends replace the rolled off UEE benefits serving to continue to reduce the forecasted load resulting from energy efficiency adoption.

The table below illustrates this process.

- Column A: Total energy before reduction of future UEE
- Column B: Total cumulative UEE
- Column C: Column B minus Historical UEE
- Column D: Roll-off amount of the incremental future UEE programs
- Column E: UEE amount to subtract from Column A
- Column F: Total energy after incorporating UEE (column A less column E)

Table C-3 UEE Program Life Process (MWh)

	A	B	C	D	E	F
	Forecast Before UEE	Total Cumulative UEE	Column B Less Historical UEE	Roll-Off Forecasted UEE	UEE to Subtract From Forecast	Forecast After UEE
2017	98,044	3,148	573	0	573	97,470
2018	99,287	3,472	942	0	942	98,345
2019	99,409	3,782	1,278	0	1,278	98,131
2020	100,736	4,087	1,605	0	1,605	99,132
2021	101,902	4,392	1,929	0	1,929	99,973
2022	102,883	4,697	2,253	0	2,253	100,630
2023	104,249	5,002	2,576	3	2,573	101,676
2024	105,784	5,307	2,897	15	2,882	102,902
2025	107,033	5,613	3,205	62	3,143	103,890
2026	108,442	5,918	3,499	135	3,365	105,078
2027	109,734	6,223	3,793	314	3,480	106,255
2028	111,136	6,528	4,099	608	3,490	107,646
2029	112,299	6,833	4,404	899	3,504	108,794
2030	113,596	7,138	4,709	1,187	3,522	110,074
2031	114,949	7,444	5,014	1,472	3,542	111,407

Results

A tabulation of class forecasts of customers and sales are given in Table C-4 and Table C-5. The sales forecasts are after all adjustments for UEE, Solar and Electric Vehicles, and are at the customer meter, excluding Wholesale.

A tabulation of the utility's forecasts, including peak loads for summer and winter seasons of each year and annual energy forecasts, both with and without the impact of UEE programs, are shown below in Tables C-6 and C-7. These projections are at generation and include Wholesale. Load duration curves, with and without UEE programs are shown as Charts C-1 and C-2.

The values in these tables reflect the loads that Duke Energy Carolinas is contractually obligated to provide and cover the period from 2017 to 2031.

For the period 2017-2031, the Spring 2016 Forecast projects an average annual compound growth rate of 1.3% for summer peaks and 1.4% for winter peaks. These rates do not reflect the impacts of

Duke Energy Carolinas UEE programs. The forecasted compound annual growth rate for energy is 1.1% before UEE program impacts are subtracted.

If the impacts of new Duke Energy Carolinas UEE programs are included, the projected compound annual growth rate for the summer peak demand is 1.2%, while winter peaks are forecasted to grow at a rate of 1.3%. The forecasted compound annual growth rate for energy is 1.0% after the impacts of UEE programs are subtracted.

The peaks and sales in the tables and charts below are at generation, except for the Class sales forecast, which is at meter.

Table C-4 Retail Customers (Thousands, Annual Average)

	Residential Customers	Commercial Customers	Industrial Customers	Other Customers	Retail Customers
2017	2,171	355	6	15	2,547
2018	2,197	359	6	16	2,578
2019	2,223	363	6	16	2,608
2020	2,247	368	6	16	2,637
2021	2,272	372	6	16	2,667
2022	2,297	377	6	16	2,696
2023	2,322	381	6	16	2,726
2024	2,347	386	6	17	2,755
2025	2,369	390	6	17	2,783
2026	2,392	395	6	17	2,811
2027	2,415	400	6	17	2,838
2028	2,438	404	6	17	2,866
2029	2,461	409	6	17	2,893
2030	2,483	414	6	18	2,921
2031	2,506	418	6	18	2,949

Note: Table 8.C differs from these values due to a 47 MW PMPA backstand contract through 2020.

Table C-5 Electricity Sales (GWh Sold - Years Ended December 31)

	Residential	Commercial	Industrial	Other	Retail
	Gwh	Gwh	Gwh	Gwh	Gwh
2017	27,797	28,710	22,430	298	79,235
2018	28,011	28,935	22,634	294	79,874
2019	28,266	29,193	22,842	289	80,591
2020	28,617	29,544	23,046	284	81,491
2021	28,880	29,881	23,218	277	82,256
2022	29,207	30,232	23,409	271	83,119
2023	29,565	30,611	23,606	265	84,046
2024	29,967	31,076	23,827	258	85,128
2025	30,296	31,462	24,013	252	86,024
2026	30,699	31,896	24,222	247	87,064
2027	31,095	32,354	24,401	241	88,091
2028	31,549	32,877	24,630	235	89,292
2029	31,917	33,331	24,815	230	90,293
2030	32,316	33,828	25,037	225	91,406
2031	32,719	34,366	25,262	223	92,569

Table C-6
Load Forecast without Energy Efficiency Programs and Before Demand Reduction Programs

YEAR	SUMMER (MW)	WINTER (MW)	ENERGY (GWH)
2017	18,830	18,473	98,044
2018	19,112	18,772	99,287
2019	19,136	18,869	99,409
2020	19,399	19,148	100,736
2021	19,685	19,513	101,902
2022	19,933	19,764	102,883
2023	20,229	20,071	104,249
2024	20,521	20,389	105,784
2025	20,837	20,638	107,033
2026	21,130	21,003	108,442
2027	21,405	21,290	109,734
2028	21,712	21,609	111,136
2029	21,998	21,929	112,299
2030	22,297	22,193	113,596
2031	22,603	22,530	114,949

Chart C-1
Load Duration Curve without Energy Efficiency Programs and Before Demand Reduction Programs

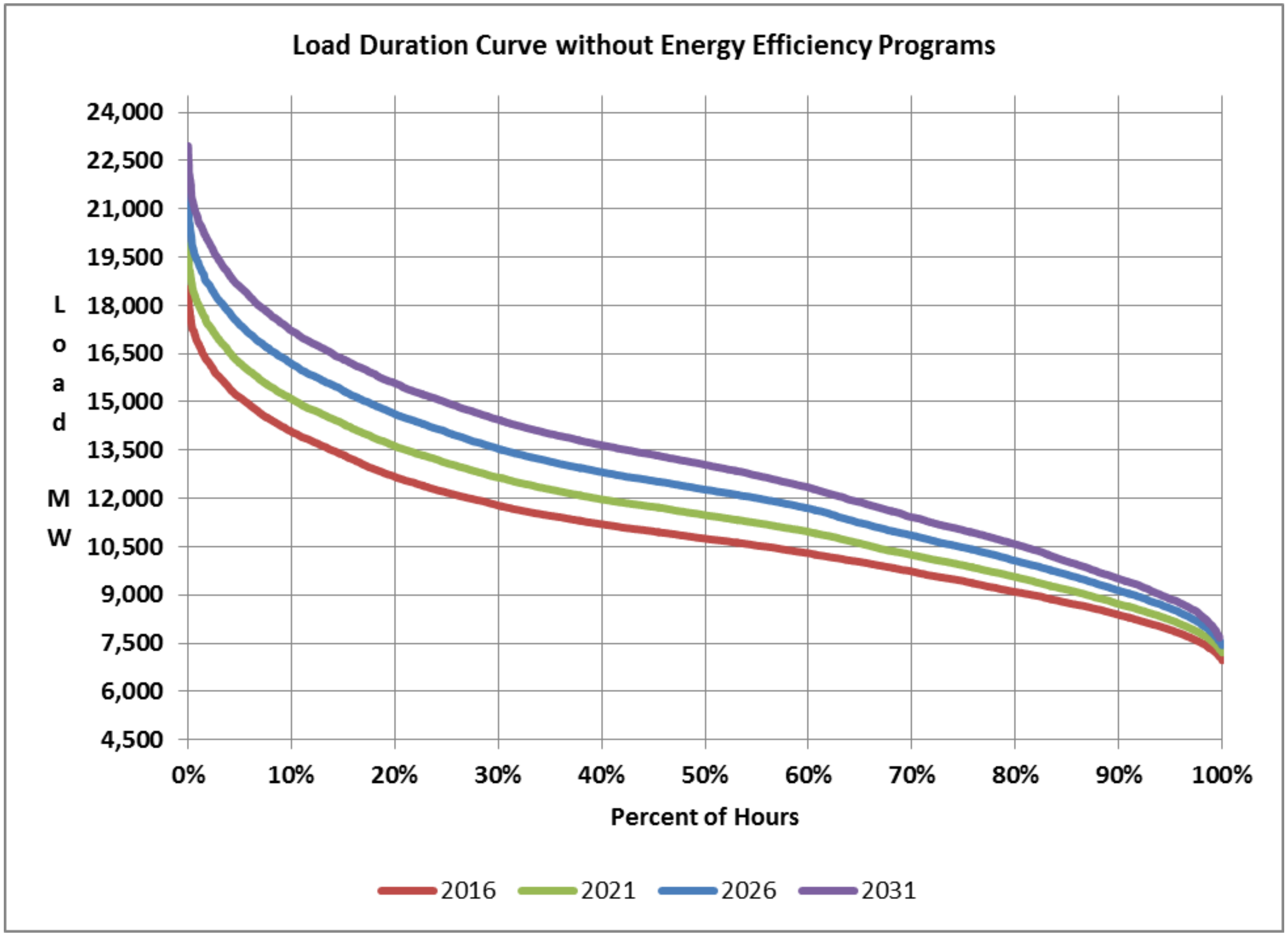
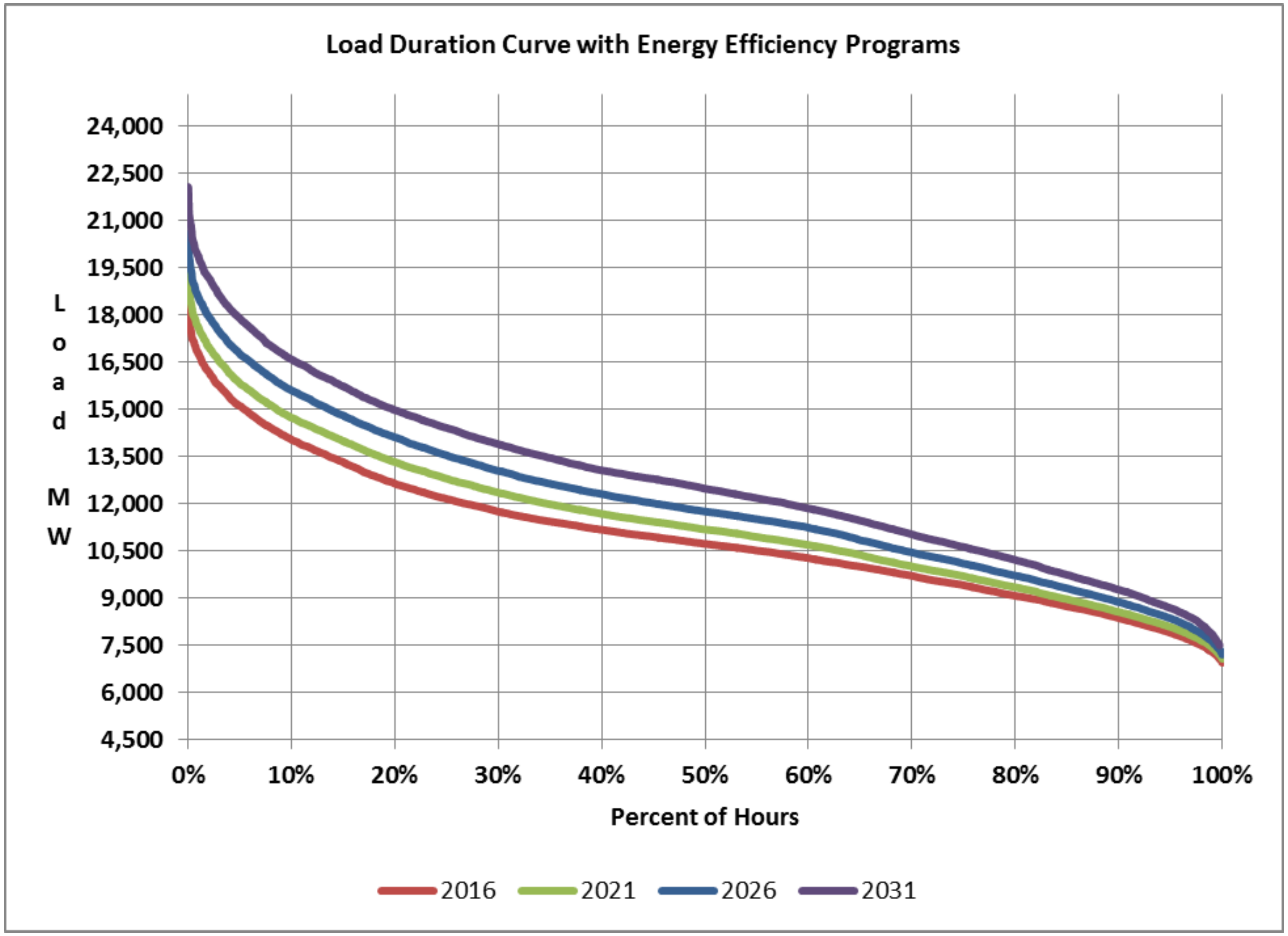


Table C-7
Load Forecast with Energy Efficiency Programs and Before Demand Reduction Programs

YEAR	SUMMER (MW)	WINTER (MW)	ENERGY (GWH)
2017	18,729	18,416	97,470
2018	18,948	18,665	98,345
2019	18,916	18,721	98,131
2020	19,127	18,957	99,132
2021	19,362	19,259	99,973
2022	19,562	19,466	100,630
2023	19,804	19,731	101,676
2024	20,046	20,011	102,902
2025	20,321	20,223	103,890
2026	20,581	20,570	105,078
2027	20,842	20,844	106,255
2028	21,146	21,161	107,646
2029	21,427	21,478	108,794
2030	21,723	21,734	110,074
2031	22,028	22,068	111,407

Chart C-2
Load Duration Curve with Energy Efficiency Programs & Before Demand Reduction Programs



APPENDIX D: ENERGY EFFICIENCY AND DEMAND SIDE MANAGEMENT

Current Energy Efficiency and Demand-Side Management Programs

DEC uses EE and DSM programs in its IRP to efficiently and cost-effectively alter customer demands and reduce the long-run supply costs for energy and peak demand. These programs can vary greatly in their dispatch characteristics, size and duration of load response, certainty of load response, and level and frequency of customer participation. In general, programs are offered in two primary categories: EE programs that reduce energy consumption and DSM programs that reduce peak demand (demand-side management or demand response programs and certain rate structure programs). Following are the EE and DSM programs available through DEC as of December 31, 2015:

Residential Customer Programs

- Appliance Recycling Program
- Energy Assessments Program
- Energy Efficiency Education Program
- Energy Efficient Appliances and Devices
- Heating, Ventilation and Air Conditioning (HVAC) Energy Efficiency Program
- Multi-Family Energy Efficiency Program
- My Home Energy Report
- Income-Qualified Energy Efficiency and Weatherization Program
- Power Manager

Non-Residential Customer Programs

- Non-Residential Smart $aver® Energy Efficient Food Service Products Program
- Non-Residential Smart $aver® Energy Efficient HVAC Products Program
- Non-Residential Smart $aver® Energy Efficient IT Products Program
- Non-Residential Smart $aver ®Energy Efficient Lighting Products Program
- Non-Residential Smart $aver® Energy Efficient Process Equipment Products Program
- Non-Residential Smart $aver® Energy Efficient Pumps and Drives Products Program
- Non-Residential Smart $aver® Custom Program
- Non-Residential Smart $aver® Custom Energy Assessments Program
- Small Business Energy Saver
- Smart Energy in Offices
- PowerShare®

- PowerShare® CallOption
- EnergyWise^{SM} for Business

In addition, based on feedback from stakeholders, the Company has developed a pilot program for non-residential customers that has received Commission approval and the expected impacts are included in this IRP analysis.

Pilot Program

- Business Energy Report Pilot

Energy Efficiency Programs

Energy Efficiency programs are typically non-dispatchable education or incentive-based programs. Energy and capacity savings are achieved by changing customer behavior or through the installation of more energy-efficient equipment or structures. All cumulative effects (gross of Free Riders, at the Plant[11]) since the inception of these existing programs through the end of 2015 are summarized below. Please note that the cumulative impacts listed below include the impact of any Measurement and Verification performed since program inception and also note that a "Participant" in the information included below is based on the unit of measure for specific energy efficiency measure (e.g. number of bulbs, kWh of savings, tons of refrigeration, etc.), and may not be the same as the number of customers that actually participate in these programs. The following provides more detail on DEC's existing EE programs:

Residential Programs

Appliance Recycling Program promotes the removal and responsible disposal of operating refrigerators and freezers from DEC residential customers. The refrigerator or freezer must have a capacity of at least 10 cubic feet but not more than 30 cubic feet. The Program recycles approximately 95% of the material from the harvested appliances.

The implementation vendor for this program abruptly discontinued operations in November 2015. As a result, the program is not currently being offered to customers and future potential impacts associated with this program beyond 2016 were not included in this IRP analysis.

[11] "Gross of Free Riders" means that the impacts associated with the EE programs have not been reduced for the impact of Free Riders. "At the Plant" means that the impacts associated with the EE programs have been increased to include line losses.

Appliance Recycling Program			
	Number of	Gross Savings (at plant)	
Cumulative as of:	Participants	MWh Energy	Peak kW
December 31, 2015	30,827	31,549	4,314

Residential Energy Assessments Program provides eligible customers with a free in-home energy assessment performed by a Building Performance Institute (BPI) certified energy specialist designed to help customers reduce energy usage and save money. The BPI certified energy specialist completes a 60 to 90 minute walk through assessment of a customer's home and analyzes energy usage to identify energy savings opportunities. The energy specialist discusses behavioral and equipment modifications that can save energy and money with the customer. The customer also receives a customized report that identifies actions the customer can take to increase their home's efficiency.

In addition to a customized report, customers receive an energy efficiency starter kit with a variety of measures that can be directly installed by the energy specialist. The kit includes measures such as energy efficiency lighting, low flow shower head, low flow faucet aerators, outlet/switch gaskets, weather stripping and an energy saving tips booklet.

Residential Energy Assessments			
	Number of	Gross Savings (at plant)	
Cumulative as of:	Participants	MWh Energy	Peak kW
December 31, 2015	50,246	49,715	7,926

Two previously offered Residential Energy Assessment measures were no longer offered in the new portfolio effective January 1, 2014. The historical performance of these measures through December 31, 2013 is included below.

Personalized Energy Report			
	Number of	Gross Savings (at plant)	
Cumulative as of:	Participants	MWh Energy	Peak kW
December 31, 2013	86,333	24,502	2,790

Online Home Energy Comparison Report			
	Number of	**Gross Savings (at plant)**	
Cumulative as of:	**Participants**	**MWh Energy**	**Peak kW**
December 31, 2013	12,902	3,547	387

Energy Efficiency Education Program is designed to educate students in grades K-12 about energy and the impact they can have by becoming more energy efficient and using energy more wisely. In conjunction with teachers and administrators, the Company will provide educational materials and curriculum for targeted schools and grades that meet grade-appropriate state education standards. The curriculum and engagement method may vary over time to adjust to market conditions, but currently utilizes theatre to deliver the program into the school. Enhancing the message with a live theatrical production truly captures the children's attention and reinforces the classroom and take-home assignments. Students learn about EE measures in the Energy Efficiency Starter Kit and then implement these energy saving measures in their homes. Students are sharing what they have learned with their parents and helping their entire households learn how to save more energy.

Energy Efficiency Education Program			
	Number of	**Gross Savings (at plant)**	
Cumulative as of:	**Participants**	**MWh Energy**	**Peak kW**
December 31, 2015	128,507	32,708	5,513

Energy Efficient Appliances and Devices Program (formerly part of Residential Smart $aver® program) provides incentives to residential customers for installing energy efficient appliances and devices to drive reductions in energy usage. The program includes the following measures:

- Energy Efficient Pool Equipment: This measure encourages the purchase and installation of energy efficient equipment and controls. Initially, the measure will focus on variable speed pumps, but the pool equipment offerings may evolve with the marketplace to include additional equipment options and control devices that reduce energy consumption and/or demand.
- Energy Efficient Lighting: This measure encourages the installation of energy efficient lighting products and controls. The product examples may include, but are not limited to the following: standard compact fluorescent light bulbs (CFLs), specialty CFLs, A lamp light emitting diodes (LEDs), specialty LEDs, CFL fixtures, LED fixtures, 2X

incandescent, LED holiday lighting, motion sensors, photo cells, timers, dimmers and daylight sensors.

- Energy Efficient Water Heating and Usage: This measure encourages the adoption of heat pump water heaters, insulation, temperature cards and low flow devices.
- Other Energy Efficiency Products and Services: Other cost-effective measures may be added to in-home installations, purchases, enrollments and events. Examples of additional measures may include, without limitation, outlet gaskets, switch gaskets, weather stripping, filter whistles, fireplace damper seals, caulking, smart strips and energy education tools/materials.

Residential Smart $aver® Program – Residential CFLs			
	Number of	Gross Savings (at plant)	
Cumulative as of:	Participants	MWh Energy	Peak kW
December 31, 2015	31,424,759	1,267,996	135,691

Residential Smart $aver® Program – Specialty Lighting			
	Number of	Gross Savings (at plant)	
Cumulative as of:	Participants	MWh Energy	Peak kW
December 31, 2015	1,175,317	51,027	6,195

Residential Smart $aver® Program – Water Measures			
	Number of	Gross Savings (at plant)	
Cumulative as of:	Participants	MWh Energy	Peak kW
December 31, 2015	414,788	32,271	3,163

Residential Smart $aver® Program – Pool Equipment			
	Number of	Gross Savings (at plant)	
Cumulative as of:	Participants	MWh Energy	Peak kW
December 31, 2015	469	1,167	294

Heating, Ventilation, and Air Conditioning (HVAC) Energy Efficiency Program (formerly part of Residential Smart $aver® program) provides residential customers with opportunities to lower their home's electric use through maintenance and improvements to their central HVAC system(s) as well as the structure of their home's building envelope and duct system(s). This program reaches Duke Energy Carolinas customers during the decision-making process for measures included in the program. Each measure offered through the program will have a prescribed incentive associated with successful completion by an approved contractor. The prescriptive and a-la-carte design of the program allows customers to implement individual, high priority measures in their homes without having to commit to multiple measures and higher price tags. The measures eligible for incentives through the program are:

- Central Air Conditioner
- Heat Pump
- Attic Insulation and Air Sealing
- Duct Sealing
- Duct Insulation
- Central Air Conditioner Tune Up
- Heat Pump Tune Up

As of the time of the analysis for this IRP, the cost effectiveness of this program had declined below the allowable threshold and, as a result, projected impacts from this program were not included in the analysis for this IRP. However, work is underway to improve the cost effectiveness and a proposal was submitted and approved by the NC Public Staff (NCPS) and the SC Office of Regulatory Staff (ORS) to implement a revised program design, subject to evaluation of the results after the first year of the program.

Residential Smart $aver® Program -- HVAC			
	Number of	**Gross Savings (at plant)**	
Cumulative as of:	**Participants**	**MWh Energy**	**Peak kW**
December 31, 2015	71,446	54,295	16,031

Residential Smart $aver® Program -- Tune and Seal			
	Number of	**Gross Savings (at plant)**	
Cumulative as of:	**Participants**	**MWh Energy**	**Peak kW**
December 31, 2015	2,361	1,402	441

Multi-Family Energy Efficiency Program provides energy efficient technologies to be installed in multi-family dwellings, which include, but are not limited to, the following:

- Energy Efficient Lighting
- Energy Efficient Water Heating Measures
- Other cost-effective measures may be added to in-home installations, purchases, enrollments and events. Examples of additional measures may include, without limitation, outlet gaskets, switch gaskets, weather stripping, filter whistles, fireplace damper seals, caulking, smart strips and energy education tools/materials.

Residential Smart $aver® Program – Property Manager CFLs			
	Number of	Gross Savings (at plant)	
Cumulative as of:	Participants	MWh Energy	Peak kW
December 31, 2015	1,080,822	46,608	4,800

Residential Smart $aver® Program – Multi Family Water Measures			
	Number of	Gross Savings (at plant)	
Cumulative as of:	Participants	MWh Energy	Peak kW
December 31, 2015	223,812	18,283	1,715

My Home Energy Report Program provides residential customers with a comparative usage report up to twelve times a year that engages and motivates customers by comparing energy use to similar residences in the same geographical area based upon the age, size and heating source of the home. The report also empowers customers to become more efficient by providing them with specific energy saving recommendations to improve the efficiency of their homes. The actionable energy savings tips, as well as measure-specific coupons, rebates or other Company program offers that may be included in a customer's report are based on that specific customer's energy profile.

My Home Energy Report Program			
	Number of	Gross Savings (at plant)	
Capability as of:	Participants	MWh Energy	Peak kW
December 31, 2015	1,045,780	228,776	61,770

Income-Qualified Energy Efficiency and Weatherization Program consists of three distinct components designed to provide EE to different segments of its low income customers:

- The Residential Neighborhood Program (RNP) is available only to individually-metered residences served by Duke Energy Carolinas in neighborhoods selected by the Company, which are considered low-income based on third party and census data, which includes income level and household size. Neighborhoods targeted for participation in this program will typically have approximately 50% or more of the households with income below 200% of the poverty level established by the U.S. Government. This approach allows the Company to reach a larger audience of low income customers than traditional government agency flow-through methods. The program provides customers with the direct installation of measures into the home to increase the EE and comfort level of the home. Additionally, customers receive EE education to encourage behavioral changes for managing energy usage and costs.
- The Company recognizes the existence of customers whose EE needs surpass the standard low cost measure offerings provided through RNP. In order to accommodate customers needing this more substantial assistance, the Company will also offer the following two programs that are deployed in conjunction with the existing government-funded North Carolina Weatherization Assistance Program when feasible. Collaborating with these programs will result in a reduction of overhead and administration costs.
- The Refrigerator Replacement Program (RRP) includes, but is not limited to, replacement of inefficient operable refrigerators in low income households. The program will be available to homeowners, renters, and landlords with income qualified tenants that own a qualified appliance. Income eligibility for RRP will mirror the income eligibility standards for the North Carolina Weatherization Assistance Program.

Income Qualified Energy Efficiency and Weatherization Program			
	Number of	Gross Savings (at plant)	
Cumulative as of:	Participants	MWh Energy	Peak kW
December 31, 2015	32,122	14,343	2,341

Non-Residential

The Non-Residential Smart $aver® programs are listed separately below by technology but for the purpose of reporting the historical performance, all of the historical impacts are combined into a single Non-Residential Smart $aver® total.

Non-Residential Smart $aver® Energy Efficient Food Service Products Program provides prescriptive incentive payments to non-residential customers to encourage and partially offset the cost of the installation of new high efficiency food service equipment in new and existing non-residential establishments and repairs to maintain or enhance efficiency levels in currently installed equipment. Measures include, but are not limited to, commercial refrigerators and freezers, steam cookers, pre-rinse sprayers, vending machine controllers, and anti-sweat heater controls.

Non-Residential Smart $aver® Energy Efficient HVAC Products Program provides prescriptive incentive payments to non-residential customers to encourage and partially offset the cost of the installation of new high efficient HVAC equipment in new and existing non-residential establishments and efficiency-directed repairs to maintain or enhance efficiency levels in currently installed equipment. Measures include, but are not limited to, chillers, unitary and rooftop air conditioners, programmable thermostats, and guest room energy management systems.

Non-Residential Smart $aver® Energy Efficient Information Technologies (IT) Products Program provides prescriptive incentive payments to non-residential customers to encourage and partially offset the cost of the installation of high efficiency new IT equipment in new and existing non-residential establishments and efficiency-directed repairs to maintain or enhance efficiency levels in currently-installed equipment. Measures include, but are not limited to, Energy Star-rated desktop computers and servers, PC power management from network, server virtualization, variable frequency drives (VFD) for computer room air conditioners and VFD for chilled water pumps.

Non-Residential Smart $aver® Energy Efficient Lighting Products Program provides prescriptive incentive payments to non-residential customers to encourage and partially offset the cost of the installation of new high efficiency lighting equipment in new and existing non-residential establishments and the efficiency-directed repairs to maintain or enhance efficiency levels in currently installed equipment. Measures include, but are not limited to, interior and exterior LED lamps and fixtures, reduced wattage and high performance T8 systems, T8 and T5 high bay fixtures, and occupancy sensors.

Non-Residential Smart $aver® Energy Efficient Process Equipment Products Program provides prescriptive incentive payments to non-residential customers to encourage and partially offset the cost of the installation of new high efficiency equipment in new and existing non-residential establishments and efficiency-directed repairs to maintain or enhance high efficiency levels in currently installed equipment. Measures include, but are not limited to, VFD air compressors, barrel wraps, and pellet dryer insulation.

Non-Residential Smart $aver® Energy Efficient Pumps and Drives Products Program provides prescriptive incentive payments to non-residential customers to encourage and partially offset the cost of the installation of new high efficiency equipment in new and existing non-residential establishments and efficiency-directed repairs to maintain or enhance efficiency levels in currently installed equipment. Measures include, but are not limited to, pumps and VFD on HVAC pumps and fans.

Non-Residential Smart $aver® Custom Program provides custom incentive payments to non-residential customers to encourage and partially offset the cost of the installation of new high efficiency equipment in new and existing non-residential establishments. This program allows for eligible customers to apply for and the Company to provide custom incentives in the amount up to 75% of the installed cost difference between standard equipment and new higher efficiency equipment or efficiency-directed repair activities in order to cover measures and efficiency-driven activities that are not offered in the various Non-Residential Smart $aver prescriptive programs.

Non-Residential Smart $aver® Custom Energy Assessments Program provides customers who may be unaware of EE opportunities at their facilities with a custom incentive payment in the amount up to 50% of the costs of a qualifying energy assessment. The purpose of this component of the program is to overcome financial barriers by off-setting a customer's upfront costs to identify and evaluate EE projects that will lead to the installation of energy efficient measures. The scope of an energy assessment may include but is not limited to a facility energy audit, a new construction/renovation energy performance simulation, a system energy study and retro-commissioning service. After the energy assessment is complete, program participants may receive an additional custom incentive payment in the amount of up to 75% of the installed cost difference between standard equipment and higher efficiency equipment or efficiency-directed repair activities.

Non-Residential Smart $aver® Program			
	Number of	Gross Savings (at plant)	
Cumulative as of:	Participants	MWh Energy	Peak kW
December 31, 2015	6,296,781	1,261,051	203,580

Small Business Energy Saver Program is designed to reduce energy usage by improving energy efficiency through the offer and installation of eligible energy efficiency measures. Program measures address major end-uses in lighting, refrigeration, and HVAC applications. The Program is available to existing non-residential establishments served on a Duke Energy Carolinas general service or industrial rate schedule from the Duke Energy Carolinas' retail distribution system that are not opted-out of the EE portion of Rider EE. Program participants must have an average annual demand of 100 kW or less per active account. Participants may be owner-occupied or tenant facilities with owner permission.

Small Business Energy Saver Program			
Cumulative as of:	Number of Participants	Gross Savings (at plant)	
		MWh Energy	Peak kW
December 31, 2015	67,564,358	71,127	15,603

Smart Energy in Offices Program is designed to increase the energy efficiency of targeted customers by engaging building occupants, tenants, property managers and facility teams with information, education, and data to drive behavior change and reduce energy consumption. This Program leverages communities to target owners and managers of potential participating accounts by providing participants with detailed information on the account/building's energy usage, support to launch energy saving campaigns, information to make comparisons between their building's energy performance and others within their community and actionable recommendations to improve their energy performance. The Program is available to existing non-residential accounts located in eligible commercial buildings served on a Duke Energy Carolinas' general service rate schedule from the Duke Energy Carolinas' retail distribution system that are not opted out of the EE portion of the Rider EE.

Smart Energy in Offices Program			
Cumulative as of:	Number of Participants	Gross Savings (at plant)	
		MWh Energy	Peak kW
December 31, 2015	65,027,594	69,071	14,376

In addition, the impacts from the Smart Energy Now Pilot program are included below:

Smart Energy Now Pilot			
	Number of	**Gross Savings (at plant)**	
Cumulative as of:	**Participants**	**MWh Energy**	**Peak kW**
December 31, 2015	70	25,093	804

<u>Pilot</u>

Business Energy Report Pilot is a periodic comparative usage report that compares a customer's energy use to their peer groups. Comparative groups are identified based on the customer's energy use, type of business, operating hours, square footage, geographic location, weather data and heating/cooling sources. Pilot participants will receive targeted energy efficiency tips in their report informing them of actionable ideas to reduce their energy consumption. The recommendations may include information about other Company offered energy efficiency programs. Participants will receive at least six reports over the course of a year.

Demand Side Management Programs

DEC's current DSM programs will be presented in two sections: Demand Response Direct Load Control Programs and Demand Response Interruptible Programs and Related Rate Tariffs.

Demand Response – Direct Load Control Programs

These programs can be dispatched by the utility and have the highest level of certainty due to the participant not having to directly respond to an event. DEC's current direct load control programs are:

<u>Residential</u>

Power Manager® provides residential customers a voluntary demand response program that allows Duke Energy Carolinas to limit the run time of participating customers' central air conditioning (cooling) systems to reduce electricity demand. Power Manager® may be used to completely interrupt service to the cooling system when the Company experiences capacity problems. In addition, the Company may intermittently interrupt (cycle) service to the cooling system. For their participation in Power Manager®, customers receive bill credits during the billing months of June through September.

Power Manager® provides DEC with the ability to reduce and shift peak loads, thereby enabling a corresponding deferral of new supply-side peaking generation and enhancing system reliability.

Participating customers are impacted by (1) the installation of load control equipment at their residence, (2) load control events which curtail the operation of their air conditioning unit for a period of time each hour, and (3) the receipt of bill credits from DEC in exchange for allowing DEC the ability to control their electric equipment.

Power Manager® Program			
Cumulative as of:	**Participants (customers)**	**Devices (switches)**	**Summer 2015 Capability (MW)**
December 31, 2015	179,017	213,030	487

The following table shows Power Manager® program activations that were not for testing purposes from June 1, 2014 through December 31, 2015.

Power Manager® Program Activations*			
Start Time	**End Time**	**Duration (Minutes)**	**MW Load Reduction**
September 2, 2014 – 2:30 PM	September 2, 2014 – 6:00 PM	210	194
September 11, 2014 – 2:30 PM	September 11, 2014 – 6:00 PM	210	194
September 16, 2014 – 2:30 PM	September 16, 2014 – 6:00 PM	210	202
June 16, 2015 – 2:30 PM	June 16, 2015 – 6:00 PM	210	228
June 23, 2015 – 2:30 PM	June 23, 2015 – 6:00 PM	210	228
July 20, 2015 – 3:30 PM	July 20, 2015 – 6:00 PM	150	168
August 5, 2015 – 2:30 PM	August 5, 2015 – 6:00 PM	210	232

Non-Residential

Demand Response – Interruptible Programs and Related Rate Structures

These programs rely either on the customer's ability to respond to a utility-initiated signal requesting curtailment, or on rates with price signals that provide an economic incentive to reduce or shift load. Timing, frequency, and nature of the load response depend on customers' actions after notification of an event or after receiving pricing signals. Duke Energy Carolinas' current interruptible and time-of-use rate programs include:

Interruptible Power Service (IS) (North Carolina Only) **-** Participants agree contractually to reduce their electrical loads to specified levels upon request by DEC. If customers fail to do so during an interruption, they receive a penalty for the increment of demand exceeding the specified level.

IS Program		
Cumulative as of:	**Participants**	**Summer 2015 Capability (MW)**
December 31, 2015	53	166

The following table shows IS program activations that were not for testing purposes from July 1, 2014 through December 31, 2015.

IS Program Activations			
Start Time	**End Time**	**Duration (Minutes)**	**MW Load Reduction**
January 8, 2015 5:00 AM	January 8, 2015 10:00 AM	300	124
January 9, 2015 5:00 AM	January 9, 2015 8:00 AM	180	138
February 19, 2015 6:00 AM	February 19, 2015 8:30 AM	150	127
February 20, 2015 6:00 AM	February 20, 2015 8:30 AM	150	109

Standby Generator Control (SG) (North Carolina Only) **-** Participants agree contractually to transfer electrical loads from the DEC source to their standby generators upon request of the Company. The generators in this program do not operate in parallel with the DEC system and therefore, cannot "backfeed" (i.e., export power) into the DEC system.

Participating customers receive payments for capacity and/or energy, based on the amount of capacity and/or energy transferred to their generators.

SG Program		
Cumulative as of:	**Participants**	**Summer 2015 Capability (MW)**
December 31, 2015	29	22

The following table shows SG program activations that were not for testing purposes from July 1, 2014 through December 31, 2015.

SG Program Activations			
Start Time	**End Time**	**Duration (Minutes)**	**MW Load Reduction**
January 8, 2015 5:00 AM	January 8, 2015 10:00 AM	300	18
January 9, 2015 5:00 AM	January 9, 2015 8:00 AM	180	18
February 19, 2015 6:00 AM	February 19, 2015 8:30 AM	150	18
February 20, 2015 6:00 AM	February 20, 2015 8:30 AM	150	18

PowerShare® is a non-residential curtailment program consisting of four options: an emergency only option for curtailable load (PowerShare® Mandatory), an emergency only option for load curtailment using on-site generators (PowerShare® Generator), an economic based voluntary option (PowerShare® Voluntary) and a combined emergency and economic option that allows for increased notification time of events (PowerShare® CallOption).

PowerShare® Mandatory: Participants in this emergency only option will receive capacity credits monthly based on the amount of load they agree to curtail during utility-initiated emergency events. Participants also receive energy credits for the load curtailed during events. Customers enrolled may also be enrolled in PowerShare® Voluntary and eligible to earn additional credits.

PowerShare® Mandatory Program		
Cumulative as of:	**Participants**	**Summer 2015 Capability (MW)**
December 31, 2015	168	371

The following table shows PowerShare® Mandatory program activations that were <u>not</u> for testing purposes from July 1, 2014 through December 31, 2105.

PowerShare® Mandatory Program Activations			
Start Time	**End Time**	**Duration (Minutes)**	**MW Load Reduction**
January 8, 2015 5:00 AM	January 8, 2015 10:00 AM	300	333
January 9, 2015 5:00 AM	January 9, 2015 8:00 AM	180	313
February 19, 2015 6:00 AM	February 19, 2015 8:30 AM	150	311
February 20, 2015 6:00 AM	February 20, 2015 8:30 AM	150	310

PowerShare® Generator: Participants in this emergency only option will receive capacity credits monthly based on the amount of load they agree to curtail (i.e. transfer to their on-site generator) during utility-initiated emergency events and their performance during monthly test hours. Participants also receive energy credits for the load curtailed during events.

PowerShare® Generator Statistics		
As of:	**Participants**	**Summer 2015 Capability (MW)**
December 31, 2015	41	49

The following table shows PowerShare® Generator program activations that were not for testing purposes from July 1, 2014 through December 31, 2015.

PowerShare® Generator Program Activations			
Start Time	**End Time**	**Duration (Minutes)**	**MW Load Reduction**
February 20, 2015 6:00 AM	February 20, 2015 8:00 AM	120	31

In response to EPA regulations finalized January 2013, the manner in which PowerShare® Generator was dispatched was modified as of May 1, 2014 to allow customers with emergency generators to continue participation in demand response programs. To comply with the new rule, dispatch of the PowerShare® Generator program had to be limited to NERC Level II (EEA2) except for the monthly readiness tests. More recently, on May 1, 2016, the DC Circuit Court of Appeals mandated vacatur of the provision that included demand response participation in the rule's 100 hour allowance. The vacatur resulted in the inability of a majority of existing PowerShare® Generator participants to continue participation as of May 1, 2016.

PowerShare® Voluntary: Enrolled customers will be notified of pending emergency or economic events and can log on to a website to view a posted energy price for that particular event. Customers will then have the option to participate in the event and will be paid the posted energy credit for load curtailed. Since this is a voluntary event program, no capacity benefit is recognized for this program and no capacity incentive is provided. The values below represent participation in PowerShare® Voluntary only and do not double count the participants in PowerShare® Mandatory that also participate in PowerShare® Voluntary.

PowerShare® Voluntary Program		
As of:	**Participants**	**Summer 2015 Capability (MW)**
December 31, 2015	3	N/A

The following table shows PowerShare® Voluntary program activations that were not for testing purposes from July 1, 2014 through December 31, 2015.

PowerShare® Voluntary Program Activations			
Start Time	**End Time**	**Duration (Minutes)**	**MW Load Reduction**
January 8, 2015 5:00 AM	January 8, 2015 10:00 AM	300	0
January 9, 2015 5:00 AM	January 9, 2015 10:00 AM	300	0
February 19, 2015 6:00 AM	February 19, 2015 10:00 AM	240	0
February 20, 2015 6:00 AM	February 20, 2015 10:00 AM	240	0

PowerShare® CallOption: This program offers a participating customer the ability to receive credits when the customer agrees, at the Company's request, to reduce and maintain its load by a minimum of 100 kW during Emergency and/or Economic Events. Credits are paid for the load available for curtailment, and charges are applicable when the customer fails to reduce load in accordance with the participation option it has selected. Participants are obligated to curtail load during emergency events. CallOption offers four participation options to customers: PS 0/5, PS 5/5, PS 10/5 and PS 15/5. All options include a limit of five Emergency Events and set a limit for Economic Events to 0, 5, 10 and 15 respectively.

PowerShare® CallOption Program		
As of:	**Participants**	**Summer 2015 Capability (MW)**
December 31, 2015	0	0

The PowerShare® CallOption program was not activated during the period from July 1, 2014 through December 31, 2015.

PowerShare® CallOption 200: This CallOption offering is targeted at customers with very flexible load and curtailment potential of up to 200 hours of economic load curtailment each year. This option will function essentially in the same manner as the Company's other CallOption offers.

However, customers who participate would experience considerably more requests for load curtailment for economic purposes. Participants remain obligated to curtail load during up to 5 emergency events.

PowerShare® CallOption 200 Program		
As of:	**Participants**	**Summer 2015 Capability (MW)**
December 31, 2015	0	0

The PowerShare® CallOption 200 program was not activated during the period from July 1, 2014 through December 31, 2015.

EnergyWise℠ for Business: is both an energy efficiency and demand response program for non-residential customers that allows DEC to reduce the operation of participants air conditioning units to mitigate system capacity constraints and improve reliability of the power grid.

Program participants can choose between a Wi-Fi thermostat or load control switch that will be professionally installed for free on each air conditioning or heat pump unit. In addition to equipment choice, participants can also select the cycling level they prefer (i.e., a 30%, 50% or 75% reduction of the normal on/off cycle of the unit). During a conservation period, DEC will send a signal to the thermostat or switch to reduce the on time of the unit by the cycling percentage selected by the participant. Participating customers will receive a $50 annual bill credit for each unit at the 30% cycling level, $85 for 50% cycling, or $135 for 75% cycling. Participants that have a heat pump unit with electric resistance emergency/back up heat and choose the thermostat can also participate in a winter option that allows control of the emergency/back up heat at 100% cycling for an additional $25 annual bill credit. Participants will also be allowed to override two conservation periods per year.

Participants choosing the thermostat will be given access to a portal that will allow them to set schedules, adjust the temperature set points, and receive energy conservation tips and communications from DEC. In addition to the portal access, participants will also receive conservation period notifications, so they can make adjustments to their schedules or notify their employees of the upcoming conservation periods.

The DEC EnergyWise℠ for Business program was implemented in South Carolina in December 2015, followed by North Carolina in January 2016.

EnergyWise^{SM} for Business Program			
		MW Capability	
Cumulative as of:	Participants	Summer	Winter
December 31, 2015	27	0.085	---

Future EE and DSM Programs

DEC is continually seeking to enhance its EE and DSM portfolio by: (1) adding new programs or expanding existing programs to include additional measures, (2) program modifications to account for changing market conditions and new M&V results, and (3) other EE pilots.

Potential new programs and/or measures will be reviewed with the DSM Collaborative then submitted to the Public Utility Commissions as required for approval.

EE and DSM Program Screening

The Company uses the DSMore model to evaluate the costs, benefits, and risks of EE and DSM programs and measures. DSMore is a financial analysis tool designed to estimate of the capacity and energy values of EE and DSM measures at an hourly level across distributions of weather conditions and/or energy costs or prices. By examining projected program performance and cost effectiveness over a wide variety of weather and cost conditions, the Company is in a better position to measure the risks and benefits of employing EE and DSM measures versus traditional generation capacity additions, and further, to ensure that DSM resources are compared to supply side resources on a level playing field.

The analysis of energy efficiency and demand side management cost-effectiveness has traditionally focused primarily on the calculation of specific metrics, often referred to as the California Standard tests: Utility Cost Test, Rate Impact Measure Test, Total Resource Cost Test and Participant Test. DSMore provides the results of those tests for any type of EE or DSM program.

- The UCT compares utility benefits (avoided costs) to the costs incurred by the utility to implement the program, and does not consider other benefits such as participant savings or societal impacts. This test compares the cost (to the utility) to implement the measures with the savings or avoided costs (to the utility) resulting from the change in magnitude and/or the pattern of electricity consumption caused by implementation of the program. Avoided costs are considered in the evaluation of cost-effectiveness based on the projected cost of power, including the projected cost of the utility's environmental compliance for known regulatory requirements. The cost-effectiveness analyses also incorporate avoided transmission and distribution costs, and load (line) losses.

- The RIM Test, or non-participants test, indicates if rates increase or decrease over the long-run as a result of implementing the program.
- The TRC Test compares the total benefits to the utility and to participants relative to the costs to the utility to implement the program along with the costs to the participant. The benefits to the utility are the same as those computed under the UCT. The benefits to the participant are the same as those computed under the Participant Test, however, customer incentives are considered to be a pass-through benefit to customers. As such, customer incentives or rebates are not included in the TRC.
- The Participant Test evaluates programs from the perspective of the program's participants. The benefits include reductions in utility bills, incentives paid by the utility and any State, Federal or local tax benefits received.

The use of multiple tests can ensure the development of a reasonable set of cost-effective DSM and EE programs and indicate the likelihood that customers will participate.

Energy Efficiency and Demand-Side Management Program Forecasts

The NCUC, in their approval of the 2014 Integrated Resource Plans and REPS Compliance Plans dated June 26, 2015 in Docket E-100, Sub141, issued the following Orders relative to EE/DSM analysis and forecasts:

7. *That the IOUs should continue to monitor and report any changes of more than 10% in the energy and capacity savings derived from DSM and EE between successive IRPs, and evaluate and discuss any changes on a program-specific basis. Any issues impacting program deployment should be thoroughly explained and quantified in future IRPs.*

8. *That each IOU shall continue to include a discussion of the status of EE market potential studies or updates in their future IRPs.*

These two Orders that are specific to EE and DSM are addressed in the following sections.

<u>Forecast Methodology</u>

In 2011, DEC commissioned a new EE market potential study to obtain new estimates of the technical, economic and achievable potential for EE savings within the DEC service area. The final report was prepared by Forefront Economics Inc. and H. Gil Peach and Associates, LLC and was completed on February 23, 2012 and included an achievable potential for planning year 5 and an economic potential for planning year 20.

The Forefront study results are suitable for IRP purposes and for use in long-range system planning models. This study also helps to inform utility program planners regarding the extent of EE opportunities and to provide broadly defined approaches for acquiring savings. This study did not, however, attempt to closely forecast EE achievements in the short-term or from year to year. Such an annual accounting is highly sensitive to the nature of programs adopted as well as the timing of the introduction of those programs. As a result, it was not designed to provide detailed specifications and work plans required for program implementation. The study provides part of the picture for planning EE programs. Fully implementable EE program plans are best developed considering this study along with the experience gained from currently running programs, input from DEC program managers and EE planners, feedback from the DSM Collaborative and with the possible assistance of implementation contractors. An updated Market Potential Study is currently underway and the results of that study should be available in time for the next DEC IRP process.

DEC prepared a Base Portfolio savings projection that was based on DEC's five year program plan for years 2016-2020. For periods beyond 2020, the Base Portfolio assumed that the annual savings projected for 2020 would continue to be achieved in each year thereafter until such time as the total cumulative EE projections reached approximately 60% of the Economic Potential as estimated by the Market Potential Study described above. This level of cumulative EE savings was projected to be reached in 2032. For periods beyond 2032, DEC assumed that additional EE savings impacts would continue to be achieved, however, the annual amount of those savings would be reduced to a level required to maintain the same cumulative EE achievement as a percentage of the Economic Potential. In other words, sufficient EE savings would be added to keep up with growth in the customer load.

Additionally, for the Base Portfolio described above, DEC included an assumption for the purpose of the IRP analysis that, when the EE measures included in the forecast reach the end of their useful lives, the impacts associated with these measures are removed from the future projected EE impacts. This concept of "rolling off" the impacts from EE programs is explained further in Appendix C of this document.

The table below provides the Base Case projected MWh load impacts of all DEC EE programs implemented since the approval of the save-a-watt recovery mechanism in 2009 on a Gross and Net of Free Riders basis. The Company assumes total EE savings will continue to grow on an annual basis throughout the planning period until reaching approximately 60% of the Economic Potential in about 2032, however, the components of future programs are uncertain at this time and will be informed by the experience gained under the current plan. Please note that this table includes a column that shows historical EE program savings since the inception of the EE programs in 2009 through the end of 2015, which accounts for approximately an additional 3,260 gigawatt-hour (GWh) of energy. The projections also do not include savings from DEC's proposed Integrated Voltage-VAR Control (IVVC) program, which will be discussed later in this document.

The following forecast is for the Base Portfolio without the effects of "rolloff":

Base Portfolio MWh Load Impacts of EE Programs

Year	Annual MWh Load Reduction - Gross		Annual MWh Load Reduction - Net	
	Including measures added in 2016 and beyond	Including measures added since 2009	Including measures added in 2016 and beyond	Including measures added since 2009
2009-15		3,260,201		2,908,086
2016	455,532	3,715,733	355,019	3,263,105
2017	922,544	4,182,745	724,529	3,632,615
2018	1,337,250	4,597,451	1,048,922	3,957,008
2019	1,736,531	4,996,732	1,358,414	4,266,500
2020	2,132,744	5,392,945	1,663,582	4,571,668
2021	2,528,958	5,789,159	1,968,750	4,876,836
2022	2,925,171	6,185,372	2,273,918	5,182,004
2023	3,321,385	6,581,586	2,579,086	5,487,172
2024	3,717,598	6,977,799	2,884,254	5,792,340
2025	4,113,812	7,374,013	3,189,422	6,097,508
2026	4,510,026	7,770,226	3,494,590	6,402,676
2027	4,906,239	8,166,440	3,799,758	6,707,844
2028	5,302,453	8,562,653	4,104,927	7,013,013
2029	5,698,666	8,958,867	4,410,095	7,318,181
2030	6,094,880	9,355,081	4,715,263	7,623,349
2031	6,491,093	9,751,294	5,020,431	7,928,517

**Please note that the MWh totals included in the tables above represent the annual year-end impacts associated with EE programs, however, the MWh totals included in the load forecast portion of this document represent the sum of the expected hourly impacts.*

The MW impacts from the EE programs are included in the Load Forecasting section of this IRP. The table below provides the Base Case projected MW load impacts of all current and projected DEC DSM programs.

Base Portfolio Load Impacts of DSM Programs

Year	Annual Peak MW Reduction					
	IS	SG	PowerShare	PowerManager	EnergyWise for Business	Total Annual Peak
2016	115	15	374	478	3	985
2017	109	15	380	502	9	1,015
2018	103	14	391	522	18	1,048
2019	98	13	401	540	27	1,079
2020	94	13	412	555	36	1,109
2021	89	12	416	555	45	1,117
2022	88	12	416	555	45	1,115
2023	88	12	416	555	45	1,115
2024	88	12	416	555	45	1,115
2025	88	12	416	555	45	1,115
2026	88	12	416	555	45	1,115
2027	88	12	416	555	45	1,115
2028	88	12	416	555	45	1,115
2029	88	12	416	555	45	1,115
2030	88	12	416	555	45	1,115
2031	88	12	416	555	45	1,115

Note: For DSM programs, Gross and Net are the same.

DEC's approved EE plan is consistent with the requirement set forth in the Cliffside Unit 6 CPCN Order to invest 1% of annual retail electricity revenues in EE and DSM programs, subject to the results of ongoing collaborative workshops and appropriate regulatory treatment.

However, pursuing EE and DSM initiatives is not expected to meet all of the future incremental peak demand for energy. DEC still envisions the need to secure additional generation, including cost-effective renewable generation, but the EE and DSM programs offered by DEC will address a significant portion of this need if such programs perform as expected.

EE Savings Variance since last IRP

In response to Order number 7 in the NCUC Order Approving Integrated Resource Plans and REPS Compliance Plans regarding the 2014 Biennial IRPs, the Base Portfolio EE savings forecast of MWh is within 10% of the forecast presented in the 2014 IRP when compared on the cumulative achievements at year 2031 of the forecasts as shown in the table below.

Base Case Comparison to 2014 IRP - Gross

Year	2014 IRP		2016 IRP		% Change from 2014 to 2016 IRP
	Annual MWh Load Reduction		Annual MWh Load Reduction		
	Including measures added in 2014 and beyond	Including measures added since 2009	Including measures added in 2016 and beyond	Including measures added since 2009	
2014	439,799	2,646,334			
2015	845,866	3,052,401		3,260,201	6.8%
2016	1,272,833	3,479,369	455,532	3,715,733	6.8%
2017	1,712,712	3,919,247	922,544	4,182,745	6.7%
2018	2,161,679	4,368,214	1,337,250	4,597,451	5.2%
2019	2,637,421	4,843,957	1,736,531	4,996,732	3.2%
2020	3,119,267	5,325,803	2,132,744	5,392,945	1.3%
2021	3,670,534	5,877,069	2,528,958	5,789,159	-1.5%
2022	4,272,614	6,479,150	2,925,171	6,185,372	-4.5%
2023	4,891,005	7,097,541	3,321,385	6,581,586	-7.3%
2024	5,489,403	7,695,938	3,717,598	6,977,799	-9.3%
2025	6,097,058	8,303,594	4,113,812	7,374,013	-11.2%
2026	6,607,562	8,814,097	4,510,026	7,770,226	-11.8%
2027	7,073,440	9,279,976	4,906,239	8,166,440	-12.0%
2028	7,490,168	9,696,704	5,302,453	8,562,653	-11.7%
2029	7,788,479	9,995,015	5,698,666	8,958,867	-10.4%
2030	8,029,871	10,236,407	6,094,880	9,355,081	-8.6%
2031	8,179,558	10,386,094	6,491,093	9,751,294	-6.1%

High EE Savings Projection

The Base Portfolio level EE forecast described above encompasses what the Company expects is achievable given the information about the economic potential and the achievable potential. In addition to this Base Portfolio level EE forecast, DEC also prepared a High Portfolio EE savings projection that assumed that the same types of programs offered in the Base Portfolio, including potential new technologies, can be offered at higher levels of participation provided that additional money is spent on program costs to encourage additional customers to participate. The High Portfolio included in the IRP modeling assumed a 50% increase in participation for all of the Base Portfolio programs, with the exception of programs already designed to reach all eligible participants in the Base Portfolio, including the various behavioral programs (MyHER, Business Energy Reports and Smart Energy in Offices). In addition, due to changes in the costs and availability of LED lighting technologies, programs in the Base Portfolio related to CFL lighting were assumed to be fully addressed in the Base Portfolio, however, the High Portfolio assumes that additional KWh savings will be captured through LED programs. Additionally, the High Portfolio assumed the same "rolling-off" assumption that was included in the Base Portfolio. Specifically, that when the EE measures included in the forecast reach the end of their useful lives, the impacts associated with those measures are removed from the future projected EE impacts.

The High Portfolio EE savings projections are higher than the expected achievable savings based on the Market Potential Study. The effort to achieve this High Portfolio would require a substantial expansion of DEC's current Commission-approved EE portfolio. More importantly, significantly higher levels of customer participation would need to be generated.

The tables below show the projected High Portfolio savings on both Gross and Net of Free Riders basis.

The following forecast is for the High Portfolio without the effects of "rolloff":

High Portfolio MWh Load Impacts of EE Programs

Year	Annual MWh Load Reduction - Gross		Annual MWh Load Reduction - Net	
	Including measures added in 2016 and beyond	Including measures added since 2009	Including measures added in 2016 and beyond	Including measures added since 2009
2009-15		3,260,201		2,908,086
2016	685,166	3,945,367	537,272	3,445,358
2017	1,381,813	4,642,014	1,089,036	3,997,122
2018	2,026,153	5,286,354	1,595,682	4,503,768
2019	2,655,067	5,915,268	2,087,427	4,995,513
2020	3,280,915	6,541,116	2,574,848	5,482,934
2021	3,906,763	7,166,964	3,062,270	5,970,356
2022	4,532,611	7,792,812	3,549,691	6,457,777
2023	5,158,458	8,418,659	4,037,113	6,945,199
2024	5,784,306	9,044,507	4,524,534	7,432,620
2025	6,410,154	9,670,355	5,011,956	7,920,042
2026	7,036,002	10,296,203	5,499,377	8,407,463
2027	7,661,849	10,922,050	5,986,799	8,894,885
2028	8,287,697	11,547,898	6,474,220	9,382,306
2029	8,913,545	12,173,746	6,961,641	9,869,727
2030	9,539,393	12,799,593	7,449,063	10,357,149
2031	10,165,240	13,425,441	7,936,484	10,844,570

At this time, there is significant uncertainty in the development of new technologies that will impact the level of EE achievement from future programs and/or enhancements to existing programs, as well as in the ability to secure high levels of customer participation, to risk including the high EE savings projection in the base assumptions for developing the 2016 IRP. DEC expects that over time, as EE programs are implemented, the Company will continue to gain experience and evidence on the viability of the level of EE achieved given actual customer participation. As information becomes available on actual participation, technology changes, and EE achievement, then the EE savings forecast used for integrated resource planning purposes will be revised in future IRP's to reflect the most realistic projection of EE savings.

Programs Evaluated but Rejected

Duke Energy Carolinas has not rejected any cost-effective programs as a result of its EE and DSM program screening.

Looking to the Future - Grid Modernization (Smart Grid Impacts)

Duke Energy Carolinas is reviewing an Integrated Volt-Var Control project that will better manage the application and operation of voltage regulators (the Volt) and capacitors (the VAR) on the Duke Energy Carolinas distribution system. In general, the project tends to optimize the operation of these devices, resulting in a "flattening" of the voltage profile across an entire circuit, starting at the substation and continuing out to the farthest endpoint on that circuit. This flattening of the voltage profile is accomplished by automating the substation level voltage regulation and capacitors, line capacitors and line voltage regulators while integrating them into a single control system. This control system continuously monitors and operates the voltage regulators and capacitors to maintain the desired "flat" voltage profile. Once the system is operating with a relatively flat voltage profile across an entire circuit, the resulting circuit voltage at the substation can then be operated at a lower overall level. Lowering the circuit voltage at the substation results in an immediate reduction of system loading.

The deployment of an IVVC program for Duke Energy Carolinas is anticipated to take approximately four years following project approval. The proposed project timeline was adjusted to reflect current strategic priorities and moved out approximately five years. Therefore, the IVVC program is projected to reduce future distribution-only peak needs by 0.20% in 2023, 0.4% in 2024, 0.6% in 2025, 1.0% in 2026 and beyond.

APPENDIX E: FUEL SUPPLY

Duke Energy Carolinas' current fuel usage consists primarily of coal and uranium. Oil and gas have traditionally been used for peaking generation, but natural gas has begun to play a more important role in the fuel mix due to lower pricing and the addition of a significant amount of combined cycle generation. These additions will further increase the importance of gas to the Company's generation portfolio. A brief overview and issues pertaining to each fuel type are discussed below.

Natural Gas

During 2015, spot Henry Hub natural gas prices averaged approximately $2.60 per million BTU (MMBtu) and U.S. lower-48 net dry production averaged approximately 72 billion cubic feet per day (BCF/day). For 2016, natural gas spot prices at the Henry Hub averaged approximately $2.27 in January 2016. Henry Hub spot pricing decreased throughout the remaining winter months and reached a low of approximately $1.485 per MMBtu on March 5, 2016. The decline in short-term spot prices during the first quarter of 2016 were driven by both fundamental supply and demand factors.

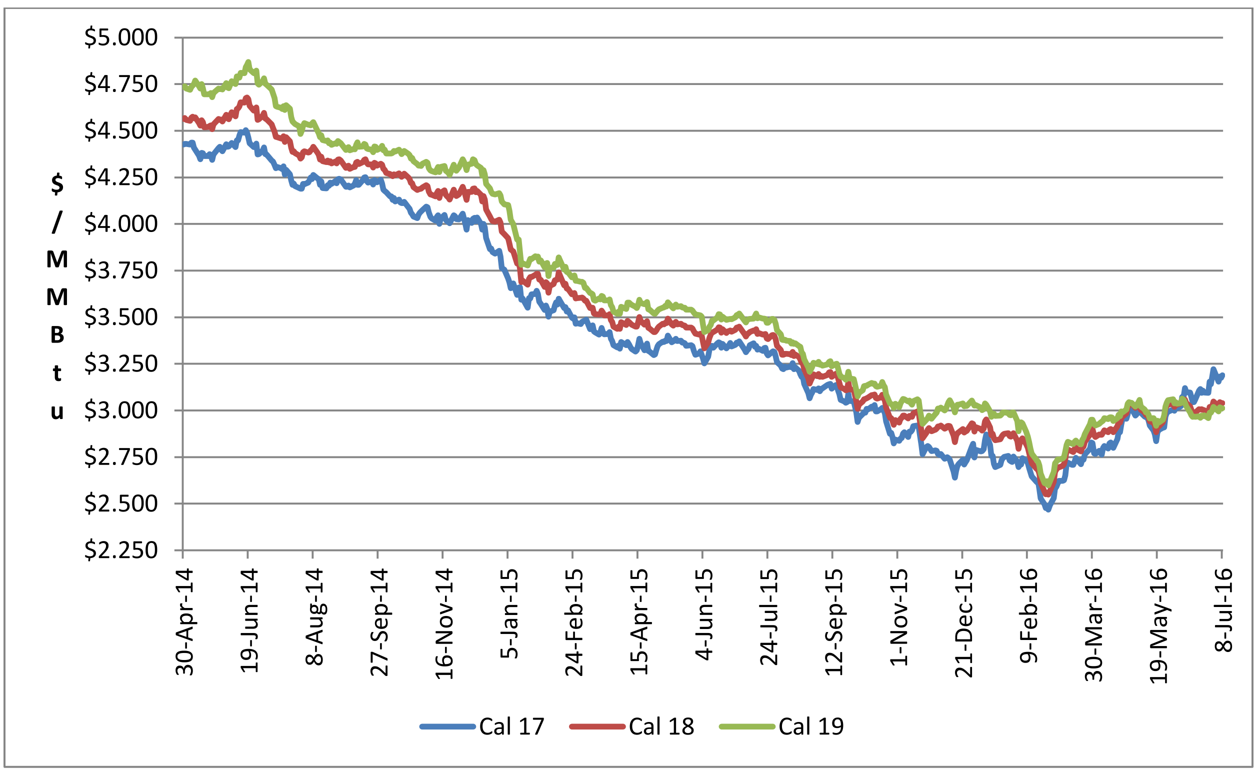
Average daily U.S. net dry production levels of approximately 72.7 BCF/day in the first quarter of 2016 were relatively comparable with 2015 net dry production. Storage ended the winter withdrawal season at a record high of 2.47 per trillion cubic feet (TCF) on March 31, 2016. Lower-48 U.S. demand in the first quarter of 2016 was lower than normal due to the mild winter weather which lowered residential heating needs.

Summer 2016 spot natural gas prices have increased from the March 2016 lows outlined previously. The Henry Hub spot price settled in a range between approximately $2.65 to $2.85 per MMBtu in mid-July 2016. Working gas in storage remains above the 5 year average and storage balances from a year ago, although the surplus has declined over the last few months with higher gas generation burns and declining overall net dry gas production which as of August 15, 2016 is approximately 71.4 BCF/day. Observed average NYMEX Henry Hub prices for the winter period November 2016 through March 2017 have increased along with the overall market to approximately $3.09 per MMBtu from the lows observed in late February 2016. Although predicting actual storage balances at the end of the typical injection season is not possible, current projections are roughly 3.8 to 3.9 TCF of working gas in storage at the end of the injection season.

Natural gas consumption is expected to remain strong through the remainder of 2016 and 2017, due primarily to increases in electric power usage. Per the EIA's short-term energy outlook released on

July 12, 2016, this year is forecasted to be a record-setting year for gas consumption by power generators. Gas generation is forecasted to exceed coal for the first time annually and account for approximately 34% of U.S. electricity. The EIA estimates that total natural gas production has decreased approximately 1 BCF/day from February 2016 to June 2016 as the market is responding to lower market prices. Producers are right sizing their well production and cutting capex in response to lower spot and forward natural gas prices. With advanced drilling techniques, producers appear able to adjust drilling programs in response to changing market prices to shorten or extend the term of the producing well. According to Baker Hughes, as of July 15, 2016 the U.S. Natural Gas rig count was at 89. This is down from 218 natural gas last year at the same time. This represents a 19 year low in the gas rig count.

In addition to the trends in shorter term natural gas spot price levels for 2016, in late February 2016, the observed forward market prices for the periods of 2017 through 2020 declined to approximately \$2.58 per MMBtu. Prices have increased over the last few months from these historical low forward price levels to approximately \$3.03 per MMBtu as of late July 2016. This is illustrated in the graph below.



Looking forward, the forward 5 and 10 year observable market curve are at \$3.06 and \$3.37 per MMBtu, respectively as of the July 21, 2016 close. In addition, as of the close of business on

July 8, 2016, the one(1), three(3) and five(5) years strips were all approximately $3.07 per MMBtu. As illustrated with these price levels and relationships, the forward NYMEX Henry Hub price curve is extremely flat with the periods of 2018 and 2019 currently trading at discounts to 2017 prices. The gas market is expected to remain relatively stable due to a improving economic picture which may provide supply and demand to further come into balance. As noted above, demand from the power sector for 2016 is expected to be higher than coal generation due to coal retirements, which are tied to the implementation of the EPA's MATS rule covering mercury and acid gasses. This increase is expected to be followed by new demand in the industrial and LNG export sectors, which both ramp up in the 2016 through 2020 timeframe. Lastly, although the outcome and timing is uncertain given the current legal status of the Clean Power Plan, there could be additional gas demand as a result of the implementation of the previously announced EPA requirement to reduce carbon emissions.

The long-term fundamental gas price outlook continues to be little changed from previous forecast even though it includes higher overall demand. The North American gas resource picture is a story of unconventional gas production dominating the gas industry. Shale gas now accounts for approximately 60% of net natural gas production today, which has increased from approximately 38% in 2014. Per the Short-Term EIA outlook dated July 12, 2016, the EIA expects production to rise in the second half of 2016 and 2017 in response to forecasted increases in prices and liquefied natural gas (LNG) exports. Additionally, the EIA forecasts the United States transitioning from a net importer of 1.3 Tcf of natural gas in 2013 to a net exporter in 2017. Overall, the EIA expects marketed natural gas to rise by approximately 1.7% for the balance of 2016 and by 4.3% by the end of 2017.

The US power sector still represents the largest area of potential new gas demand, but increased usage is expected to be somewhat volatile as generation dispatch is sensitive to price. Looking forward, economic dispatch competition is expected to continue between gas and coal, although there has been some permanent loss in overall coal generation due to the number of coal unit retirements. Overall declines in energy consumption tend to result from the adoption of more energy-efficient technologies and policies that promote energy efficiency.

In order to ensure adequate natural gas supplies, transportation and storage, the company has gas procurement strategies that include periodic RFPs, market solicitations, and short-term market engagement activities to procure a reliable, flexible, diverse, and competitively priced natural gas supply that supports DEC's CT and CC facilities. With respect to storage and transportation needs, the company has continued to add incremental firm pipeline capacity and gas storage as it gas generation fleet as grown. The company will continue to evaluate competitive options to meet its growing need for gas pipeline infrastructure as the gas generation fleet grows.

Coal

On average, the 2016 Duke fundamental outlook for coal prices is lower than the 2015 outlook. The power sector accounted for 90.5% of total demand for coal in 2015, equivalent to 772 million tons of burn. The main determinants of power sector coal demand are natural gas prices, electricity demand growth, and non-fossil electric generation, namely nuclear, hydro, and renewables.

Low natural gas prices continue to exert extreme pressure on the coal fleet resulting in the reduction of coal's competitiveness across virtually all basins and caused generator coal stocks to reach near-term highs. Coal shipments to generators will be even lower than actual burn as these high inventory levels are worked down, a process that could take about two years.

Annual electric load growth, inclusive of energy efficiency impacts, is roughly 1%. The U.S. Supreme Court granted a stay, halting implementation of the EPA's Clean Power Plan pending the resolution of legal challenges to the program in court. Though stayed, the CPP makes retention of coal capacity less desirable. The fundamental outlook anticipates the eventual implementation of CPP beginning in 2022, resulting in a long-term decline in power generation from coal. The coal fired power plants projected to retire during the forecast period burned almost 60 million tons of coal during 2015 which represents approximately 8% of the total 2015 burn. Growth in renewable generation also contributes to the decline in coal demand.

Exports of both thermal and metallurgical coals have been hurt by the strength of the US dollar coupled with the slowing growth of the Chinese economy. In addition, China has implemented import tariffs to protect their domestic coal production.

Finally, the coal industry is in the midst of unprecedented restructuring. It is uncertain how responsive either producers or transporters of coal will be if faced with unexpected periods of increased demand.

Nuclear Fuel

To provide fuel for Duke Energy's nuclear fleet, the Company maintains a diversified portfolio of natural uranium and downstream services supply contracts from around the world.

Requirements for uranium concentrates, conversion services and enrichment services are primarily met through a portfolio of long-term supply contracts. The contracts are diversified by supplier, country of origin and pricing. In addition, DEC staggers its contracting so that its portfolio of long-term contracts covers the majority of fleet fuel requirements in the near-term and decreasing portions of the fuel requirements over time thereafter. By staggering long-term contracts over time, the Company's purchase price for deliveries within a given year consists of a blend of contract prices negotiated at many different periods in the markets, which has the effect of smoothing out the Company's exposure to price volatility. Diversifying fuel suppliers reduces the Company's exposure to possible disruptions from any single source of supply. Near-term requirements not met by long-term supply contracts have been and are expected to be fulfilled with spot market purchases.

Due to the technical complexities of changing suppliers of fuel fabrication services, DEC generally sources these services to a single domestic supplier on a plant-by-plant basis using multi-year contracts.

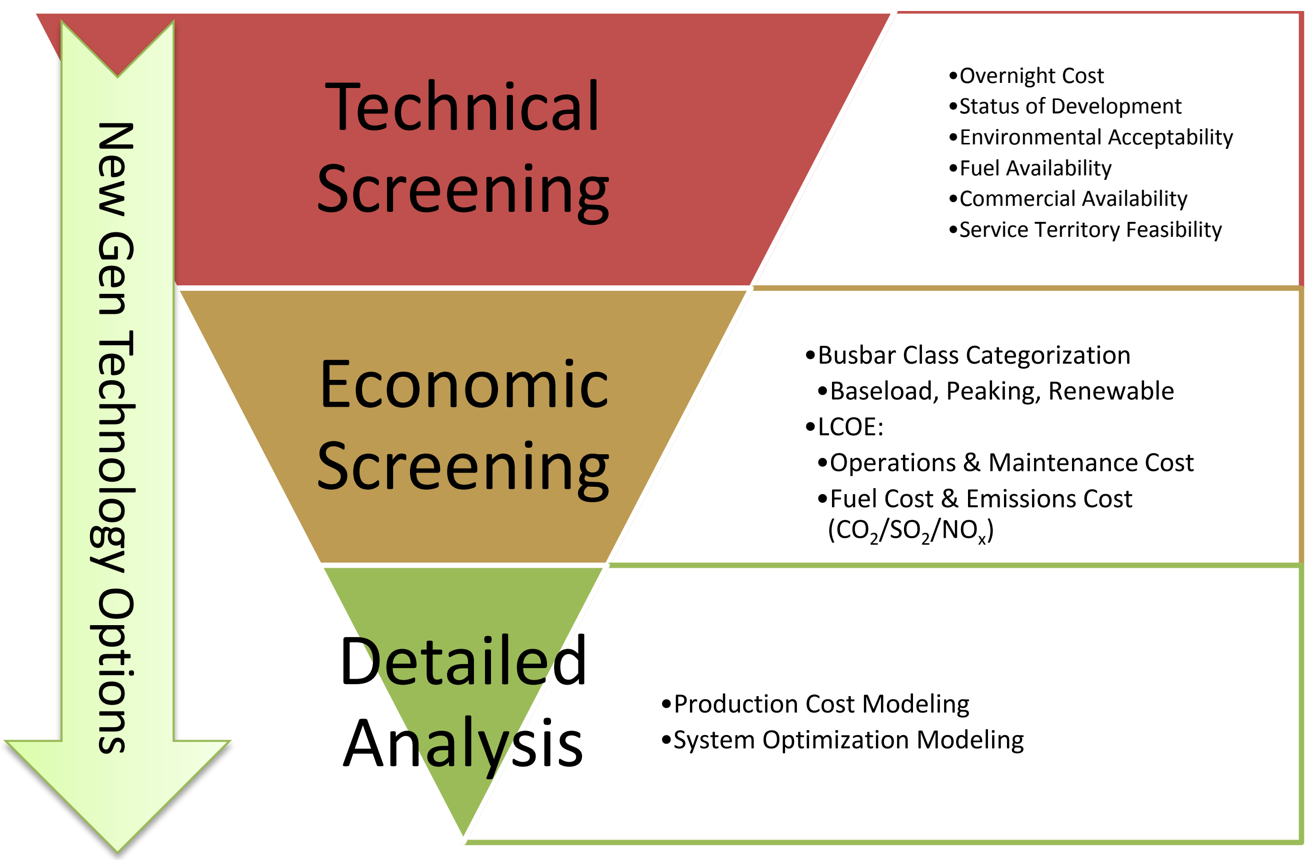
As fuel with a low cost basis is used and lower-priced legacy contracts are replaced with contracts at higher market prices, nuclear fuel expense is expected to increase in the future. Although the costs of certain components of nuclear fuel are expected to increase in future years, nuclear fuel costs are expected to be competitive with alternate generation and customers will continue to benefit from the Company's diverse generation mix.

APPENDIX F: SCREENING OF GENERATION ALTERNATIVES

The Company screens generation technologies prior to performing detailed analysis in order to develop a manageable set of possible generation alternatives. Generating technologies are screened from both a technical perspective, as well as an economic perspective. In the technical screening, technology options are reviewed to determine technical limitations, commercial availability issues and feasibility in the Duke Energy Carolinas service territory.

Economic screening is performed using relative dollar per kilowatt-year ($/kW-yr) versus capacity factor screening curves. The technologies must be technically and economically viable in order to be passed on to the detailed analysis phase of the IRP process.

New Generation Technologies Screening Process



Technical Screening

The first step in the Company's supply-side screening process for the IRP is a technical screening of the technologies to eliminate those that have technical limitations, commercial availability issues, or are not feasible in the Duke Energy Carolinas service territory. A brief explanation of the technologies excluded at this point and the basis for their exclusion follows:

- **Geothermal** was eliminated because there are no suitable geothermal resources in the region to develop into a power generation project.

- **Pumped Storage Hydropower (PSH)** is the only conventional, mature, commercial, utility-scale electricity storage option available currently. This technology consumes off-peak electricity by pumping water from a lower reservoir to an upper reservoir. When the electric grid needs more electricity and when electricity prices are higher, water is released from the upper reservoir. As the water flows from the upper reservoir to the lower reservoir, it goes through a hydroelectric turbine to generate electricity. Many operational pumped storage hydropower plants are providing electric reliability and reserves for the electric grid in high demand situations. PSH can provide a high amount of power because its only limitation is the capacity of the upper reservoir. Typically, these plants can be as large as 4,000 MW, and have an efficiency of 76% - 85% Electric Power Research Institute (EPRI, 2012). Therefore, this technology is effective at meeting electric demand and transmission overload by shifting, storing, and producing electricity. This is important because an increasing supply of intermittent renewable energy generation such as solar will cause challenges to the electric grid. PSH installations are greatly dependent on regional geography and face several challenges including: environmental impact concerns, a long permitting process, and a relatively high initial capital cost. Duke Energy currently has two PSH assets, Bad Creek Reservoir and Jocassee Hydro with an approximate combined generating capacity of 2,140 MW.

- **Compressed Air Energy Storage (CAES)**, although demonstrated on a utility scale and generally commercially available, is not a widely applied technology and remains relatively expensive. Traditional systems require a suitable storage site, commonly underground where the compressed air is used to boost the output of a gas turbine. The high capital requirements for these resources arise from the fact that suitable sites that possess the proper geological formations and conditions necessary for the compressed air storage reservoir are relatively scarce, especially in the Carolinas. However, above-ground compressed air energy storage (AGCAES) technologies are under development but at a much smaller scale, approximately 0.5 - 20MW. Several companies have attempted to develop cost effective CAES systems using above ground storage tanks. Most attempts to date have not been commercially successful, but their development is being monitored.

- **Small Modular Nuclear Reactors (SMR)** are generally defined as having capabilities of less than 300 MW. In 2012, the U.S. Department of Energy (DOE) solicited bids for companies to participate in a small modular reactor grant program with the intent to "promote the accelerated commercialization of SMR technologies to help meet the nation's economic energy security and climate change objectives." SMRs are still conceptual in design and are developmental in nature. Licensing for SMR's has not been approved by the NRC at present. Currently, there is no industry experience with developing this technology outside of the conceptual phase. Duke Energy will be monitoring the progress of the SMR projects for potential consideration and evaluation for future resource plans as they provide an emission free source of fuel diverse, flexible generation.

- **Fuel Cells**, although originally envisioned as being a competitor for combustion turbines and central power plants, are now targeted to mostly distributed power generation systems. The size of the distributed generation applications ranges from a few kW to tens of MW in the long-term. Cost and performance issues have generally limited their application to niche markets and/or subsidized installations. While a medium level of research and development continues, this technology is not commercially viable/available for utility-scale application.

- **Supercritical CO_2 Brayton Cycle** is of increasing interest; however, the technology is not mature or ready for commercialization. Several pilots are underway and Duke Energy will continue to monitor their development as a potential source of future generation needs.

- **Poultry waste and swine waste digesters** remain relatively expensive and are often faced with operational and/or permitting challenges. Research, development, and demonstration continue, but these technologies remain generally too expensive or face obstacles that make them impractical energy choices outside of specific mandates calling for use of these technologies.

- **Off-shore Wind**, although demonstrated on a utility scale and commercially available, is not a widely applied technology and not easily permitted in the United States. This technology remains expensive even with the five year tax credit extension granted in December 2015 and has yet to actually be constructed anywhere in the United States. Pioneer wind farm is the first to "break water" off the coast of Rhode Island. Federal waters have not yet been released for wind turbine farm siting; however, state waters are within the rights of the State to exercise jurisdiction. Rhode Island's Block Island is within the 3-mile State waters jurisdiction but strategically located in a manner to gain enough available wind resource to support its economic feasibility. Pioneer is a 30MW demonstration that will utilize five, 6 MW Alstom wind turbines and is expected to by operational by year end 2016. The U.S. Department of the Interior's Bureau of Ocean Energy Management (BOEM) has held several auctions for offshore lease. These sites will be utilized to collect marine and wind data for potential future development of an offshore wind farm.

- **Solar Steam Augmentation** systems utilize solar thermal energy to supplement a Rankine steam cycle such as that in a fossil generating plant. The supplemental steam could be integrated into the steam cycle and support additional MW generation similar in concept to the purpose of duct firing a heat recovery steam generator. This technology, although attractive has several hurdles yet to clear, including a clean operating history and initial capital cost reductions. This technology is very site specific and Duke Energy will continue to monitor developments in the area of steam augmentation.

A brief explanation of the technology additions for 2016 and the basis for their inclusion follows:

- **Addition of Combined Heat & Power (CHP) to the IRP**

  Combined Heat and Power systems, also known as cogeneration, generate electricity and useful thermal energy in a single, integrated system. CHP is not a new technology, but an approach to applying existing technologies. Heat that is normally wasted in conventional power generation is recovered as useful energy, which avoids the losses that would otherwise be incurred from separate generation of heat and power. CHP incorporating a CT and heat recovery steam generator (HRSG) is more efficient than the conventional method of producing usable heat and power separately via a gas package boiler.

Duke Energy is exploring and working with potential customers with good base thermal loads on a regulated Combined Heat and Power offer. The CHP asset will be included as part of Duke Energy's IRP as a placeholder for future projects as described below. The steam sales are credited back to the revenue requirement of the projects to reduce the total cost of this generation grid resource, making this a low cost grid asset. Along with the potential to be a competitive cost generation resource, CHP can result in CO_2 emission reductions, deferral of T&D expenses, and present economic development opportunities for the state.

Duke Energy has publically announced its first CHP project, a 20 MW investment at Duke University. We are currently working with other industrial, military and Universities for future project expansions.

- **Addition of Battery Storage to the IRP**

Energy storage solutions are becoming an ever growing necessity in support of grid stability at peak demand times and in support of energy shifting and smoothing from renewable sources. Energy Storage in the form of battery storage is becoming more feasible with the advances in battery technology (Tesla low-cost Lithium-ion battery technology) and the reduction in battery cost; however, their uses (even within Duke Energy) have been concentrated on frequency regulation, solar smoothing, and/or energy shifting from localized renewable energy sources with a high incidence of intermittency (i.e. solar and wind applications).

Duke Energy has several projects in operation since 2011, mainly in support of regulating output voltages/frequencies from renewable energy sources to the grid. This includes projects as large as the Notrees Battery Storage project (36 MW) which supports a wind farm down to the smaller 250 kW Marshall Battery Storage Project which supports a 1.2 MW solar array. Additional examples include the Rankin Battery Storage Project (402 kW), the McAlpine Community Energy Storage Project (24 kW), McAlpine Substation Energy Storage Project (200 kW), and a 2 MW facility on Ohio's former Beckjord Station grounds. Each of these applications supports frequency regulation, solar smoothing, or energy shifting from a local solar array. These examples are only a few in support of a growing trend of coupling Battery Storage with an intermittent renewable energy source such as solar or wind in an effort to stabilize output and increase a facility's (renewable plus storage) net capacity factor.

Beginning in 2016, Distributed Energy Resources (DER), formed an Energy Storage (ES) team to develop a fifteen year battery storage prediction model and begin the development of battery storage deployment plans for the next five year budget cycle. The ES team will focus their five year plan across multiple jurisdictions, however, the first two areas that will most likely provide deployment sites are Duke Energy Indiana (DEI) (substation utility scale application) and western NC, Asheville Regional area (130kV distribution circuit assessment) in DEP. Regional battery storage modeling is proceeding in 2016 to establish battery system sites, use case designs and cost/benefit analysis. Regulatory approvals and cost recovery development will play a key role in the timing of full operational battery system deployment.

Economic Screening

The Company screens all technologies using relative dollar per kilowatt-year ($/kW-yr) versus capacity factor screening curves. The screening within each general class (Baseload, Peaking/Intermediate, and Renewables), as well as the final screening across the general classes uses a spreadsheet-based screening curve model developed by Duke Energy. This model is considered proprietary, confidential and competitive information by Duke Energy.

This screening curve analysis model includes the total costs associated with owning and maintaining a technology type over its lifetime and computes a levelized $/kW-year value over a range of capacity factors. The Company repeats this process for each supply technology to be screened resulting in a family of lines (curves). The lower envelope along the curves represents the least costly supply options for various capacity factors or unit utilizations. Some technologies have screening curves limited to their expected operating range on the individual graphs. Lines that never become part of the lower envelope, or those that become part of the lower envelope only at capacity factors outside of their relevant operating ranges, have a very low probability of being part of the least cost solution, and generally can be eliminated from further analysis.

The Company selected the technologies listed below for the screening curve analysis. While Clean Power Plan regulation may effectively preclude new coal-fired generation, Duke Energy Carolinas has included ultra-supercritical pulverized coal with carbon capture sequestration and integrated gasification combined cycle technologies with CCS of 1400 pounds/net MWh capture rate as options for base load analysis consistent with the pending version of the EPA Clean Power Plan for new coal plants. Additional detail on the expected impacts from EPA regulations to new coal-fired options is included in Appendix G. 2016 additions include Combined Heat and Power as a base load technology and Lithium ion Battery Storage as a renewable technology.

Dispatchable (Summer Ratings)

- Base load – 782 MW Ultra-Supercritical Pulverized Coal with CCS
- Base load – 557 MW 2x1 IGCC with CCS
- Base load – 2 x 1,117 MW Nuclear Units (AP1000)
- Base load – 576 MW – 1x1x1 Advanced Combined Cycle (Inlet Chiller and Fired)
- Base load – 1,160 MW – 2x2x1 Advanced Combined Cycle (Inlet Chiller and Fired)
- Base load – 20 MW – Combined Heat & Power
- Peaking/Intermediate – 166 MW 4 x LM6000 Combustion Turbines
- Peaking/Intermediate – 201 MW 12 x Reciprocating Engine Plant
- Peaking/Intermediate – 870 MW 4 x 7FA.05 Combustion Turbines
- Renewable – 2 MW / 8 MWh Li-ion Battery
- Renewable – 5 MW Landfill gas

Non-Dispatchable

- Renewable – 150 MW Wind - On-Shore
- Renewable – 5 MW Solar PV

Information Sources

The cost and performance data for each technology being screened is based on research and information from several sources. These sources include, but may not be limited to the following internal Departments: Duke Energy's Project Management & Construction, Emerging Technologies, and Generation & Regulatory Strategy. The following external sources may also be utilized: proprietary third-party engineering studies, the Electric Power Research Institute Technical Assessment Guide (TAG®), and Energy Information Administration (EIA). In addition, fuel and operating cost estimates are developed internally by Duke Energy, or from other sources such as those mentioned above, or a combination of the two. EPRI information or other information or estimates from external studies are not site-specific, but generally reflect the costs and operating parameters for installation in the Carolinas. Finally, every effort is made to ensure that capital, O&M costs, fuel costs and other parameters are current and include similar scope across the technologies being screened. The supply-side screening analysis uses the same fuel prices for coal and natural gas, and nitrogen oxides ($NO_{x)}$, sulfur dioxide ($SO_{2)}$, and CO_2 allowance prices as those utilized downstream in the detailed analysis (discussed in Appendix A). Screening curves were developed for each technology to show the economics with and without carbon costs (i.e. No Carbon Tax, Carbon Tax, System Carbon Mass Cap).

Screening Results

The results of the screening within each category are shown in the figures below. Results of the baseload screening show that natural gas combined cycle generation is the least-cost base load resource. With lower gas prices, larger capacities and increased efficiency, natural gas combined cycle units have become more cost-effective at higher capacity factors in all carbon scenario screening cases (i.e. No Carbon Tax, Carbon Tax, System Carbon Mass Cap). Although CHP is competitive with CC at the upper end of the capacity range, it is site specific, requiring a local steam and electrical load. The baseload curves also show that nuclear generation may be a cost effective option at high capacity factors with CO_2 costs included. Carbon capture systems have been demonstrated to reduce coal-fired CO_2 emissions to levels similar to natural gas and will continue to be monitored as they mature; however, their current cost and uncertainty of safe, reliable storage options has limited the technical viability of this technology.

The peaking/intermediate technology screening included F-frame combustion turbines, fast start aero-derivative combustion turbines, and fast start reciprocating engines. The screening curves show the F-frame CTs to be the most economic peaking resource unless there is a special application that requires the fast start capability of the aero-derivative CTs or reciprocating engines. Reciprocating engine plants offer the lowest heat rates and fastest start times among simple cycle options. In addition, the recent strength of the U.S. dollar compared to the Euro has led to reduced costs for reciprocating engines imported from Europe. However, the volatility of the exchange rates should be considered for the generic selection of this technology, especially with the potential British withdrawal from the European Union (EU).

The renewable screening curves show solar is a more economical alternative than wind and landfill gas generation. Solar and wind projects are technically constrained from achieving high capacity factors making them unsuitable for intermediate or baseload duty cycles. Landfill gas projects are limited based on site availability but are dispatchable. Solar projects, like wind, are not dispatchable and therefore less suited to provide consistent peaking capacity. Aside from their technical limitations, solar and wind technologies are not currently economically competitive generation technologies without State and Federal subsidies. These renewable resources do play an important role in meeting the Company's NC REPS requirements.

Centralized generation, as depicted above, will remain the backbone of the grid for Duke Energy in the long term; however, in addition it is likely that distributed generation will begin to share more and more grid responsibilities over time as technologies such as energy storage increase our grid's flexibility.

The screening curves are useful for comparing costs of resource types at various capacity factors but cannot be solely utilized for determining a long term resource plan because future units must be optimized with an existing system containing various resource types. Results from the screening curve analysis provide guidance for the technologies to be further considered in the more detailed quantitative analysis phase of the planning process.

C
O
N
F
I
D
E
N
T
I
A
L

[redacted]

C
O
N
F
I
D
E
N
T
I
A
L

C
O
N
F
I
D
E
N
T
I
A
L

[redacted]

C
O
N
F
I
D
E
N
T
I
A
L

C
O
N
F
I
D
E
N
T
I
A
L

[redacted]

C
O
N
F
I
D
E
N
T
I
A
L

C
O
N
F
I
D
E
N
T
I
A
L

[redacted]

APPENDIX G: ENVIRONMENTAL COMPLIANCE

Legislative and Regulatory Issues

Duke Energy Carolinas, which is subject to the jurisdiction of Federal agencies including the Federal Energy Regulatory Commission, EPA, and the NRC, as well as State commissions and agencies, is potentially impacted by State and Federal legislative and regulatory actions. This section provides a high-level description of several issues Duke Energy Carolinas is actively monitoring or engaged in that could potentially influence the Company's existing generation portfolio and choices for new generation resources.

Air Quality

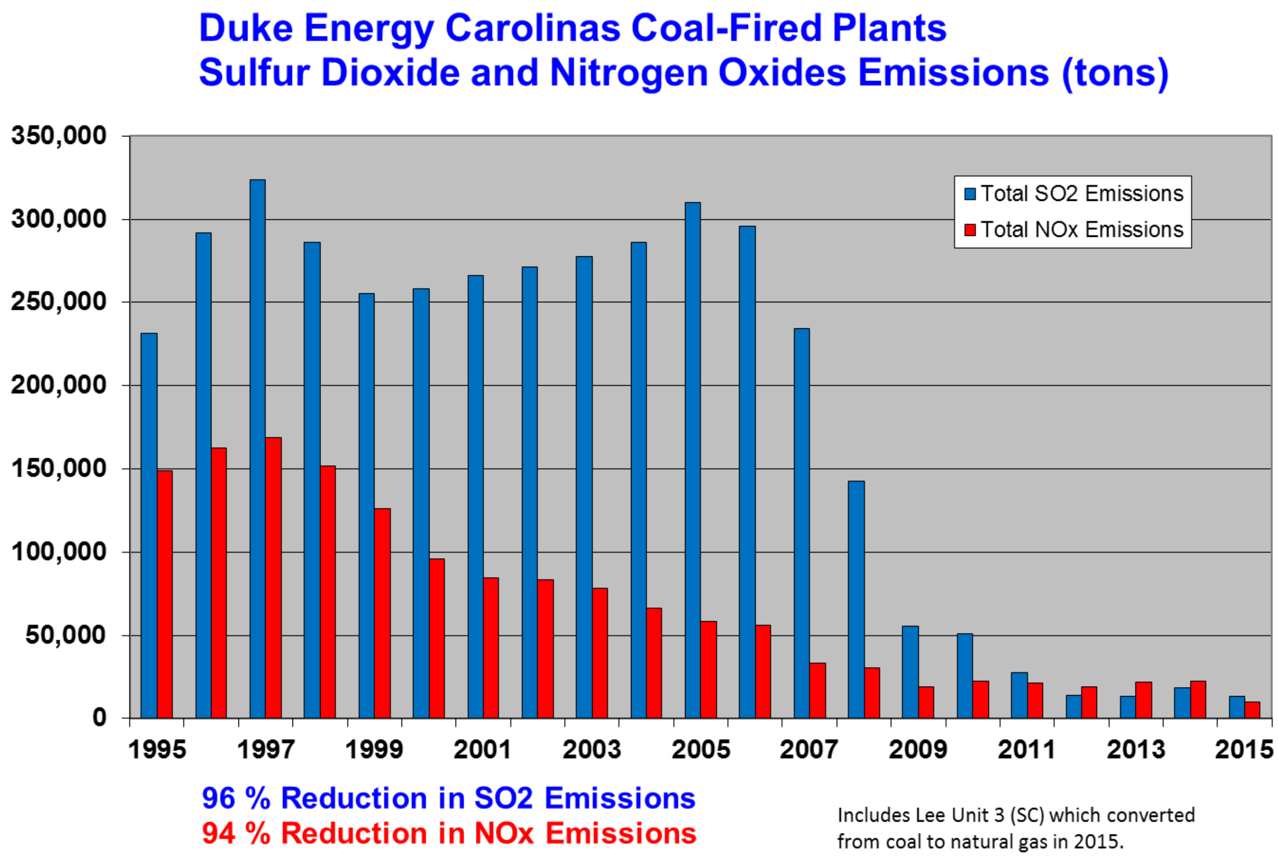
Duke Energy Carolinas is required to comply with numerous State and Federal air emission regulations, including the current Clean Air Interstate Rule (CAIR) NO_X and SO_2 cap-and-trade program and the 2002 North Carolina Clean Smokestacks Act (NC CSA).

As a result of complying with the NC CSA, Duke Energy Carolinas reduced SO_2 emissions by approximately 95% from 2000 to 2013. The law also required additional reductions in NO_X emissions in 2007 and 2009, beyond those required by CAIR, which Duke Energy Carolinas has achieved. This landmark legislation, which was passed by the North Carolina General Assembly in June of 2002, calls for some of the lowest state-mandated emission levels in the nation, and was passed with Duke Energy Carolinas' input and support.

The chart below show the significant downward trend in both NO_X and SO_2 emissions through 2015 as a result of actions taken at DEC facilities.

149

Chart G-1 DEC NO_x and SO_2 Emissions



The following is brief summary of the major air related federal regulatory programs that are currently impacting or that could impact Duke Energy Carolinas operations in North Carolina.

Cross-State Air Pollution Rule (CSAPR)

In August, 2011 the EPA finalized the Cross-State Air Pollution Rule. The CSAPR established state-level caps on annual SO_2 and NOx emissions and ozone season NOx emissions from electric generating units (EGUs) across the Eastern U.S., including North Carolina. The CSAPR was set up as a two-phase program with Phase I taking effect in 2012 and Phase II taking effect in 2014. Legal challenges to the rule resulted in Phase I implementation being delayed until 2015 and Phase II implementation being delayed until 2017. Duke Energy Carolinas has been complying with Phase I of the CSAPR and is well positioned to comply with the Phase II annual programs beginning in 2017.

The CSAPR ozone season NOx program was designed to address interstate transport for the 80 parts per billion (ppb) ozone standard that was established in 1997. In 2008 the EPA lowered the ozone standard to 75 ppb. In late 2015 the EPA proposed a rule, referred to as the CSAPR Update Rule, to revise Phase II of the CSAPR ozone season NOx program to address interstate transport for the 75 ppb standard. EPA proposed to lower the Phase II ozone season NOx emission caps for most affected states, including North Carolina, with the lower caps taking effect on May 1, 2017. The EPA has indicated that it plans to finalize the rule in the summer of 2016. Duke Energy Carolinas cannot predict the outcome of this rulemaking so it does not know at this time what, if any impact it may have on operations in North Carolina.

Mercury and Air Toxics Standards (MATS) Rule

In March 2011 the EPA proposed the Mercury and Air Toxics Standards rule to regulate emissions of mercury and other hazardous air pollutants from coal-fired EGUs. The rule establishing unit-level emission limits for mercury, acid gases, and non-mercury metals, was finalized in February, 2012. Compliance with the emission limits was required by April 16, 2015, or April 16, 2016 if the state permitting authority granted up to a 1-year compliance extension. Duke Energy Carolinas is complying with all rule requirements.

National Ambient Air Quality Standards (NAAQS)

8-Hour Ozone NAAQS

In October, 2015, EPA finalized a revision to the 8-Hour Ozone NAAQS, lowering it from 75 to 70 ppb. State recommendations to EPA regarding area designations under the 70 ppb standard are due to EPA by October 1, 2016. The EPA expects to finalize area designations by October 1, 2017 based on 2014-2016 air quality. Attainment dates for any areas designated nonattainment will depend on the area's nonattainment classification, but will not be earlier than October, 2020.

The 70 ppb ozone standard is being challenged in court by numerous parties. Some are challenging the standard as being too low, while others are challenging the standard as not being low enough. Duke Energy Carolinas cannot predict the outcome of the litigation or assess the potential impact of the lower standard on future operations in North Carolina at this time given the uncertainty surrounding area designations.

SO_2 NAAQS

On June 22, 2010, EPA finalized a rule establishing a 75 ppb 1-hour SO_2 NAAQS. Since then, EPA has completed two rounds of area designations, neither of which resulted in any areas in North Carolina being designated nonattainment.

In August, 2015, the EPA finalized its Data Requirements Rule which established requirements for state air agencies to characterize SO_2 air quality levels around certain EGUs using ambient air quality monitoring or air quality modeling. The Data Requirements Rule also laid out the timeline for state air agencies to complete air quality characterizations and submit the information to EPA, and for EPA to finalize area designations.

The North Carolina Department of Environmental Quality is characterizing SO_2 air quality around the Duke Energy Carolinas Belews Creek, Marshall, and Allen stations using air quality modeling. The modeling analyses must be submitted to EPA by January 13, 2017, and EPA must complete designations of the areas surrounding these three stations by December 31, 2017. For any area designated nonattainment, the North Carolina Department of Environmental Quality would be required to submit a state implementation plan to EPA within 18 months of the area's designation that establishes the requirements for bringing the area into attainment within 5 years of its nonattainment designation.

Fine Particulate Matter ($PM_{2.5}$) NAAQS

On December 14, 2012, the EPA finalized a rule establishing a 12 microgram per cubic meter annual $PM_{2.5}$ NAAQS. The EPA finalized area designations for this standard in December 2014. That designation process did not result in any areas in North Carolina being designated as a nonattainment area.

Greenhouse Gas Regulation

On August 3, 2015, the EPA finalized a rule establishing CO_2 new source performance standards for pulverized coal (PC) and natural gas combined cycle EGUs that initiated or that initiates construction after January 8, 2014. The EPA finalized emission standards of 1,400 lb CO_2 per gross MWh of electricity generation for PC units and 1,000 lb CO_2 per gross MWh for NGCC units. The standard for PC units can only be achieved with carbon capture and sequestration technology. Duke Energy Carolinas views the EPA rule as barring the development of new coal-fired generation because CCS is not a demonstrated and available technology for applying to PC units. Duke Energy Carolinas considers the standard for NGCC units to be achievable. Numerous parties have filed petitions with the U.S. Court of Appeals for the District of Columbia (D.C. Circuit) challenging the EPA's final emission standard for new PC units.

On August 3, 2015, the EPA finalized the Clean Power Plan, a rule to limit CO_2 emissions from existing fossil fuel-fired EGUs (existing EGUs are units that commenced construction prior to January 8, 2014). The CPP requires states to develop and submit to EPA for approval a state implementation plan designed to achieve the required CO_2 emission limitations. The CPP required states to submit an initial plan by September 6, 2016, and a final plan by September 6, 2018. The CPP established two rate-based compliance pathways and two mass-based compliance pathways for states to choose from when developing their state implementation plans. At this time it is unknown which approach the state of North Carolina might select for its implementation plan. The EPA would review and approve or disapprove state plans within 12 months of receipt. The CPP required emission limitations to take effect beginning in 2022 and get gradually more stringent through 2030.

The CPP does not directly impose regulatory requirements on Duke Energy Carolinas. An approved North Carolina state implementation plan would establish the regulatory requirements that would apply to Duke Energy Carolinas. If North Carolina were not to submit an approvable plan, EPA would impose a federal implementation plan on affected Duke Energy Carolinas EGUs to achieve the required CO_2 emission limitations.

Numerous legal challenges to the CPP were filed with the DC Circuit. Many petitioners also asked the DC Circuit to stay the rule until questions about its legal status get resolved. The DC Circuit denied motions to stay the CPP, but shortly thereafter the Supreme Court granted a stay of the rule, halting implementation of the CPP through any final decision in the case by the Supreme Court. This means the CPP has no legal effect, and EPA cannot enforce any of the deadlines or rule requirements while the stay is in place.

Briefing of the case before the D.C. Circuit was completed in April, 2016. Oral arguments before the full D.C. Circuit are scheduled for September 27, 2016. A decision by the D.C. Circuit will most likely be issued in early 2017. It is expected that the losing parties in that decision will seek Supreme Court review, and it is likely that the Supreme Court will grant review. In this event, final resolution of the case might not occur until sometime in 2018.

Generally, the CPP is designed to cause the replacement of coal-fired generation with generation from natural gas and renewable energy sources. If the CPP is ultimately upheld by the courts and implementation goes forward, Duke Energy Carolinas could incur increased fuel, purchased power, operation and maintenance and other costs for replacement generation. However, Duke Energy Carolinas is unable to assess the specific impact of the CPP on its operations at this time due to the many uncertainties currently surrounding the rule's potential implementation.

One of the uncertainties surrounding the CPP is the implementation schedule that would apply if the CPP is found to be lawful. In prior instances where a final rule has been stayed but eventually found to be lawful, all implementation dates have been delayed by at least the number of days the stay was in place. While an exact implementation schedule for the CPP under such an outcome is uncertain, what does seem certain is that if the CPP is found to be lawful, the schedule for implementation will be delayed from what is in the final rule.

Water Quality and By-product Issues

CWA 316(b) Cooling Water Intake Structures

Federal regulations implementing §316(b) of the Clean Water Act (CWA) for existing facilities were published in the Federal Register on August 15, 2014 with an effective date of October 14, 2014. The rule regulates cooling water intake structures at existing facilities to address environmental impacts from fish being impinged (pinned against cooling water intake structures) and entrained (being drawn into cooling water systems and affected by heat, chemicals or physical stress). The final rule establishes aquatic protection requirements at existing facilities and new on-site generation that withdraw 2 million gallons per day (MGD) or more from rivers, streams, lakes, reservoirs, estuaries, oceans, or other waters of the United States. All Duke Energy nuclear fueled, coal-fired and combined cycle stations, in North Carolina and South Carolina are affected sources, with the exception of Smith Energy [12].

The rule establishes two standards, one for impingement and one for entrainment. To demonstrate compliance with the impingement standard, facilities must choose and implement one of the following options:

- Closed cycle re-circulating cooling system; or
- Demonstrate the maximum design through screen velocity is less than 0.5 feet per second (fps) under all conditions; or
- Demonstrate the actual through screen velocity, based on measurement, is less than 0.5 fps; or
- Install modified traveling water screens and optimize performance through a two-year study; or
- Demonstrate a system of technologies, practices, and operational measures are optimized to reduce impingement mortality; or
- Demonstrate the impingement latent mortality is reduced to no more than 24% annually based on monthly monitoring.

In addition to these options, the final rule allows the state permitting agency to establish less stringent standards if the capacity utilization rate is less than 8% averaged over a 24-month contiguous period. The rule, also, allows the state permitting agency to determine no further action warranted if impingement is considered *de minimis*. Compliance with the impingement standard is not required until requirements for entrainment are established.

The entrainment standard does not mandate the installation of a technology but rather establishes a process for the state permitting agency to determine necessary controls, if any, required to reduce entrainment mortality on a site-specific basis. Facilities that withdraw greater than 125 MGD are required to submit information to characterize the entrainment and assess the engineering feasibility, costs, and benefits of closed-cycle cooling, fine mesh screens and other technological and operational controls. The state permitting agency can determine no further action is required, or require the installation of fine mesh screens, or conversion to closed-cycle cooling.

---

[12] Richmond County(a public water supply system) supplies cooling water to Smith Energy; therefore the rule is not applicable.

The rule requires facilities with a NPDES permit that expires after July 14, 2018 to submit all necessary 316(b) reports with the renewal application. For facilities with a NPDES permit that expire prior to July 14, 2018 or are in the renewal process, the state permitting agency is allowed to establish an alternate submittal schedule. We expect submittals to be due in the 2018 to 2021 timeframe and intake modifications, if necessary to be required in the 2019 to 2022 timeframe, depending on the NPDES permit renewal date and compliance schedule developed by the state permitting agency.

Steam Electric Effluent Guidelines

Federal regulations revising the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (ELG Rule) were published in the Federal Register on November 3, 2015 with an effective date of January 4, 2016. While the ELG Rule is applicable to all steam electric generating units, waste streams affected by these revisions are generated at DEC's coal-fired facilities. The revisions prohibit the discharge of bottom and fly ash transport water, and flue gas mercury control wastewater, and establish technology based limits on the discharge of wastewater generated by Flue Gas Desulfurization (FGD) systems, and leachate from coal combustion residual landfills and impoundments. The rule, also, establishes technology based limits on gasification wastewater, but this waste stream is not generated at any of the DEC facilities. The new limits must be incorporated into the applicable stations' National Pollutant Discharge Elimination System permit based on a date determined by the permitting authority that is as soon as possible beginning November 1, 2018, but no later than December 31, 2023, with the exception of limits for CCR leachate, which are effective upon issuance of the permit after the effective date of the rule. For discharges to publically owned treatment works (POTW), the limits must be met by November 1, 2018.

The extent to which the rule will affect a particular steam electric generating unit will depend on the treatment technology currently installed at the station. A summary of the impacts are as follows:

- Fly Ash Transport Water: All DEC coal-fired units either handling fly ash dry during normal operation or are in the process of converting to dry fly ash handling. However, to ensure fly ash is handled dry without disruptions to generation, dry fly ash reliability projects are being completed.
- Bottom Ash Transport Water: All DEC coal-fired units, except for Rogers / Cliffside 6, will be required to install a closed-loop or a dry bottom ash handling system.
- FGD Wastewater: All DEC coal-fired units, except for Rogers / Cliffside 6 will be required to upgrade or completely replace the existing FGD wastewater treatment system. Even though Allen

and Belews Creek Steam Stations utilize the model technology, which was the basis for the limits, additional treatment is expected to be required to ensure compliance.

- CCR Leachate: The revised limits for CCR leachate from impoundments and landfills are same as the existing limits for low volume waste. Potential impacts are being evaluated on a facility basis.

Coal Combustion Residuals

In January 2009, following Tennessee Valley Authority's Kingston ash pond dike failure December 2008, Congress issued a mandate to EPA to develop federal regulations for the disposal of coal combustion residuals. CCR includes fly ash, bottom ash, and flue gas desulfurization solids. In the interim, EPA conducted structural integrity inspections of all the surface impoundments nationwide that were used for disposal of CCR. In June 2010 EPA proposed the CCR rule for notice and comment and then published the final rule on April 17, 2015. The CCR rule regulates CCR as a nonhazardous waste under Subtitle D of RCRA and allows for beneficial use of CCR with some restrictions. The effective date of the rule was October 19, 2015.

The CCR rule applies to all new and existing landfills, new and existing surface impoundments receiving CCR and existing surface impoundments that are no longer receiving CCR but contain liquid located at stations currently generating electricity (regardless of fuel source). The rule establishes requirements regarding landfill design, structural integrity design and assessment criteria for surface impoundments, groundwater monitoring and protection procedures and other operational and reporting procedures to ensure the safe disposal and management of CCR.

In addition to the requirements of the federal CCR regulation, CCR landfills and surface impoundments will continue to be independently regulated by the state. On September 20, 2014, the North Carolina Coal Ash Management Act of 2014 (CAMA) became law and was amended on June 24, 2015 and amended a second time on July 15, 2016.

CAMA establishes requirements regarding the use of CCR, the closure of existing CCR surface impoundments, the disposal of CCR at active coal plants, and the handling of surface and groundwater impacts from CCR surface impoundments. CAMA requires eight CCR surface impoundments in North Carolina to be closed no later than August 1, 2019. It also required state regulators to provide risk ranking classifications to determine the method and timing for closing the remaining CCR surface impoundments. North Carolina Department of Environmental Quality (NCDEQ) has categorized all remaining CCR surface impoundments as intermediate risk. CAMA also grants NCDEQ the authority to change a impoundment's classification based on dam safety repairs completed or the removal of any threat to drinking water. The impact from both state and federal CCR regulations to Duke Energy Carolinas is significant.

APPENDIX H: NON-UTILITY GENERATION AND WHOLESALE

This appendix contains wholesale sales contracts, firm wholesale purchased power contracts and non-utility generation contracts.

Table H-1 Wholesale Sales Contracts **CONFIDENTIAL**

[redacted]

Table H-2 Firm Wholesale Purchased Power Contracts **CONFIDENTIAL**

[redacted]

Table H-3 DEC QF Interconnection Queue

Qualified Facilities contribute to the current and future resource mix of the Company. QFs that are under contract are captured as designated resources in the base resource plan. QFs that are not yet under contract but in the interconnection queue may contribute to the undesignated additions identified in the resource plans. It is not possible to precisely estimate how much of the interconnection queue will come to fruition, however the current queue clearly supports solar generation's central role in DEC's NC REPS compliance plan.

Below is a summary of the interconnection queue as of June 30, 2016:

Utility	FacilityState	Energy Source Type	Number of Pending Projects	Pending Capacity (MW AC)
DEC	**NC**	Biogas	4	6.3
		Biomass	4	7.1
		Diesel	1	1.5
		Hydroelectric	1	4.0
		Landfill Gas	2	3.0
		Solar	175	709.4
DEC	**NC Total**		**187**	**731.3**
	SC	Landfill Gas	1	4.8
		Solar	80	536.1
DEC	**SC Total**		**81**	**540.9**
DEC Total			**268**	**1272.2**

Note: (1) Above table includes all QF projects that are in various phases of the interconnection queue and not yet generating energy.
(2) Table does not include net metering interconnection requests.

APPENDIX I: TRANSMISSION PLANNED OR UNDER CONSTRUCTION

This appendix lists the planned transmission line additions and discusses the adequacy of DEC's transmission system. Table I-1 lists the line projects that are planned to meet reliability needs.

Table I-1: DEC Transmission Line Additions

	Location		Capacity	Voltage	
Year	**From**	**To**	**MVA**	**KV**	**Comments**
2016	Peach Valley Tie	Riverview Switching Station	N/A	230	Install a switchable 3% series reactor on the Peach Valley – Riverview 230 kV transmission line.
2017	Ripp Switching Station	Riverbend Steam Station	N/A	230	Install new switching station along the Ripp - Riverbend 230kV transmission line to tie in new NTE generation.
2022	Central Tie	Shady Grove Tie	930	230	Reconductor approximately 18 miles of the Central – Shady Grove 230 kV transmission line with bundled 954 ACSR at 120°C.

There are presently no new lines, 161 kV and above, under construction in DEC's service area.

DEC Transmission System Adequacy

Duke Energy Carolinas monitors the adequacy and reliability of its transmission system and interconnections through internal analysis and participation in regional reliability groups. Internal transmission planning looks 10 years ahead at available generating resources and projected load to identify transmission system upgrade and expansion requirements. Corrective actions are planned and implemented in advance to ensure continued cost-effective and high-quality service. The DEC transmission model is incorporated into models used by regional reliability groups in developing plans to maintain interconnected transmission system reliability. DEC works with DEP, NCEMC and ElectriCities to develop an annual NC Transmission Planning Collaborative (NCTPC) plan for the DEC and DEP systems in both North and South Carolina. In addition, transmission planning is coordinated with neighboring systems including South Carolina Electric & Gas (SCE&G) and Santee Cooper under a number of mechanisms including legacy interchange agreements between SCE&G, Santee Cooper, DEP, and DEC.

The Company monitors transmission system reliability by evaluating changes in load, generating capacity, transactions and topography. A detailed annual screening ensures compliance with DEC's Transmission Planning Guidelines for voltage and thermal loading. The annual screening uses methods that comply with SERC policy and NERC Reliability Standards and the screening results identify the need for future transmission system expansion and upgrades.

Transmission planning and requests for transmission service and generator interconnection are interrelated to the resource planning process. DEC currently evaluates all transmission reservation requests for impact on transfer capability, as well as compliance with the Company's Transmission Planning Guidelines and the FERC Open Access Transmission Tariff (OATT). The Company performs studies to ensure transfer capability is acceptable to meet reliability needs and customers' expected use of the transmission system. Generator interconnection requests are studied in accordance with the Large and Small Generator Interconnection Procedures in the OATT.

Southeastern Reliability Corporation (SERC) audits DEC every three years for compliance with NERC Reliability Standards. Specifically, the audit requires DEC to demonstrate that its transmission planning practices meet NERC standards and to provide data supporting the Company's annual compliance filing certifications. SERC conducted a NERC Reliability Standards compliance audit of DEC in May 2014. The scope of this audit included standards impacting the Transmission Planning area. DEC received "No Findings" from the audit team in the Transmission Planning area.

DEC participates in a number of regional reliability groups to coordinate analysis of regional, sub-regional and inter-balancing authority area transfer capability and interconnection reliability. The reliability groups' purpose is to:

- Assess the interconnected system's capability to handle large firm and non-firm transactions for purposes of economic access to resources and system reliability;
- Ensure that planned future transmission system improvements do not adversely affect neighboring systems; and
- Ensure interconnected system compliance with NERC Reliability Standards.

Regional reliability groups evaluate transfer capability and compliance with NERC Reliability Standards for the upcoming peak season and five- and ten-year periods. The groups also perform computer simulation tests for high transfer levels to verify satisfactory transfer capability.

Application of the practices and procedures described above have ensured DEC's transmission system is expected to continue to provide reliable service to its native load and firm transmission customers.

APPENDIX J: CROSS-REFERENCE OF IRP REQUIREMENTS AND SUBSEQUENT ORDERS

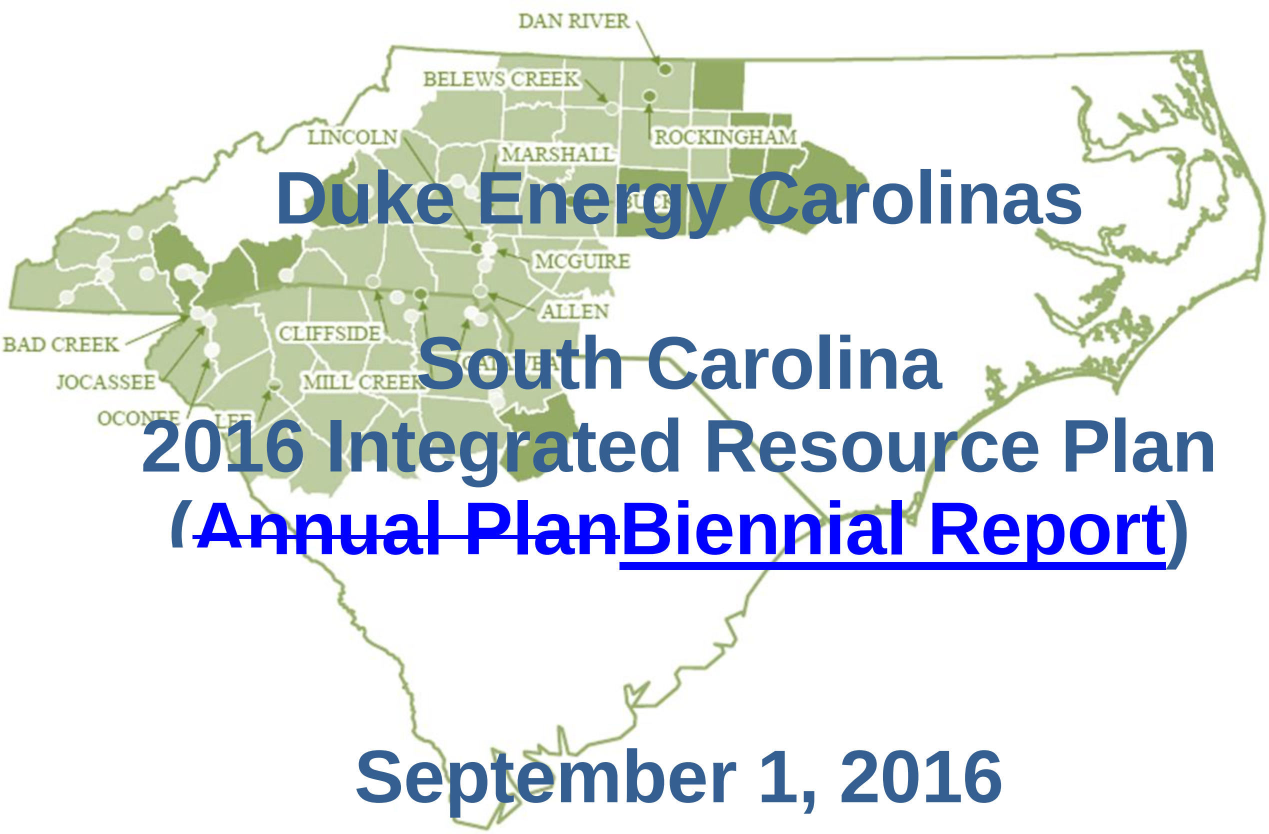
The following table cross-references IRP regulatory requirements for SC Code Ann. § 58-37-10 in South Carolina and identifies where those requirements are discussed in the IRP.

Requirement	Location	Reference	Updated
B. REQUIREMENTS FOR THE DEVELOPMENT AND COMPOSITION OF THE IRP FILING (Cont.)			
1. Environmental costs are to be considered on a monetized basis where sufficient data is available. Those environmental costs that cannot be monetized must be addressed on a qualitative basis within the planning process. Environmental costs are to be considered within the IRP to the extent that they impact. the utility's specific system costs such as meeting existing regulatory standards and such standards as ran be reasonably anticipated to occur. The term "reasonably anticipated to occur" refers to standards that are in the process of being developed and are known to be forthcoming but are not finalized at the time of analysis. This does not mean that. the utility is prohibited from incorporating factors which go beyond the above definition. Should the utility feel that other factors (environmental or other) are important and need to be incorporated within the planning process, it needs to justify within the IRP the basis for inclusion. a. Environmental costs should be monetized and included within the planning process whenever possible. To the extent that environmental costs cannot be monetized the utility must consider them on a qualitative basis in developing the plan. The same guideline applies to relevant utility and customer costs. b. Each utility must provide the general environmental standards applicable to each supply-side option and explain the impact of each supply-side option on compliance with the standards. To the extent feasible each utility should seek to identify on a quantitative basis the impact of demand-side options on the environment (i.e. reduced pollutant emissions, reduced waste disposal, increased noise pollution, etc.) Such impacts ran be reflected on a qualitative basis when quantitative information is not available. c. Each utility should identify and monetize, to the extent possible, the cost of compliance for existing and projected supply-side options.	Ch. 8, App A	SC § 58-37-10	Yes

Requirement	Location	Reference	Updated
2. Each utility must. provide a demand forecast (to include both summer and winter peak demand) and an energy forecast. Forecasting requirements for the IRP filing: a. Forecast must incorporate explicit treatment of demand-side resources. b. Forecasting methodologies should seek to incorporate "end-use" modeling techniques where they are appropriate. End-use and econometric modeling techniques can be combined where appropriate to seek accuracy while being able to address the impacts of demand-side options. c. The IRP filing must incorporate energy and peak demand forecasts that include an explanation of the forecasting methodology and modeling procedures. d. The IRP filing must incorporate summary statistics for major models; assumptions followed within the forecasting process; projected energy usage by customer class; load factors by customer class; and total system sales. The utility must file this information, either as part of the IRP or as supplemental material to the IRP. e. An analysis must be performed to assess forecast uncertainty. This can consist of a high, most likely, low scenario analysis. f. The utility should periodically test its forecasting methodology for historical accuracy. g. The utility must identify significant changes in forecasting methodology.	Ch. 3, App C	SC § 58-37-10	Yes
3. The IRP filing must include a discussion of the risk associated with the plan (risk assessment). Where feasible the impacts of potential deviations from the plan should be identified.	Ch. 8, App A	SC § 58-37-10	Yes
4. The transmission improvements and/or additions necessary to support the IRP will also be provided within the plan. This includes listing the transmission lines and other associated facilities (125 kv or more) which are under construction or proposed, including the capacity and volt. age levels, locations, and schedules for completion and operation.	App I	SC § 58-37-10	Yes

Requirement	Location	Reference	Updated
5. The plan must incorporate an evaluation and review of the existing demand-side options utilized the utility. It should identify changes in objectives and specifically identify and quantify achievements within each specific program. plan should include a description of each objectives; implementation schedule; achievements to date. An explanation be provided outlining the approaches used to measure achievements and benefits.	Ch. 4, App D	SC § 58-37-10	Yes
6. The IRP filing must identify and discuss any significant studies being conducted by the company on future demand-side and/or supply-side options.	Ch. 4, App D	SC § 58-37-10	Yes
7. The IRP must be flexible to allow for the unknowns and uncertainties that confront the plan. The IRP must have the ability to quickly adapt to changes in a manner consistent with minimizing costs while maintaining reliability.	Ch. 8, App A	SC § 58-37-10	Yes
8. The utilities must incorporate as part of their IRP's a maintenance and refurbishment program of existing units when economically viable and consistent with system reliability and planning flexibility.	App A, App I	SC § 58-37-10	Yes
9. Utilities must adequately consider all cost effective third-party power purchases including firm, unit, etc., consistent with the IRP objective statement. This involves consideration of both interconnected and non-interconnected third-party purchases. The utility will describe any consideration of joint planning with other utilities. The utility will identify all third party power purchase agreements.	App H, App A	SC § 58-37-10	Yes
10. The IRP filing must identify any major problems the utility anticipates that have the potential to impact the success of the plan and the planning process. Strategies which might be invoked to deal with each problem should be identified whenever possible.	App A	SC § 58-37-10	Yes
11. Each utility must demonstrate that the IRP incorporates not only efficient and cost. effective generation resources but also that transmission and distribution system costs are consistent with the minimization of total system costs. Any supporting information can be filed as a supplement to the IRP.	App I	SC § 58-37-10	Yes
12. Each utility must explain and/or describe any technologies included in the IRP.	Ch. 6, App F	SC § 58-37-10	Yes

Requirement	Location	Reference	Updated
13. Each future supply-side option incorporated within the identified. fuel source; anticipated generating capacity; anticipated date of initial construction; anticipated date of commercial operation; etc. provided for each option. Utility shall identify the anticipated location of future supply-side option it is consistent with the utility's proprietary interests.	Exec Summary, Ch. 8, App A	SC § 58-37-10	Yes
14. The IRP must demonstrate that each utility is pursuing those resource options available for less than the avoided costs of new supply-side alternatives. Demand-side options will included in the IRP to the extent they are cost-effective are consistent with the Commission objective statement for the IRP. Utility DSM plans shall give attention to capturing lost opportunity resources. They include those cost effective energy efficiency savings that can only be realized during a narrow time period, such as in new construction, renovation, and in routine replacement of existing equipment.	App D	SC § 58-37-10	Yes



Duke Energy Carolinas

South Carolina
2016 Integrated Resource Plan
(~~Annual Plan~~Biennial Report)

September 1, 2016

PUBLIC

2. SYSTEM OVERVIEW

DEC provides electric service to an approximately 24,088-square-mile service area in central and western North Carolina and western South Carolina. In addition to retail sales to approximately 2.48 million customers, the Company also sells wholesale electricity to incorporated municipalities and to public and private utilities. Recent historical values for the number of customers and sales of electricity by customer groupings may be found in Appendix C.

DEC currently meets energy demand, in part, by purchases from the open market, through longer-term purchased power contracts and from the following electric generation assets:

- Three nuclear generating stations with a combined capacity of 7,358 MW/7,160 MW (winter/summer)
- Four coal-fired stations with a combined capacity of 6,859 MW/ 6,821 MW (winter/summer)
- 29 hydroelectric stations (including two pumped-storage facilities) with a combined capacity of 3,238 MW (winter/summer)
- Four CT stations and two CC stations with a combined capacity of 4,607 MW/4,089 MW (winter/summer)
- 18 utility-owned solar facilities with a combined firm capacity of 3.9 MW
- One natural gas boiler with a capacity of 170 MW (winter/summer)

The Company's power delivery system consists of approximately 103,140 miles of distribution lines and 13,087 miles of transmission lines. The transmission system is directly connected to all of the Transmission Operators that surround the DEC service territory. There are 36 tie-line circuits connecting with nine different Transmission Operators: DEP, PJM Interconnection, LLC (PJM), Tennessee Valley Authority (TVA), Smokey Mountain Transmission, Southern Company, Yadkin, Southeastern Power Administration (SEPA), South Carolina Electric & Gas (SCE&G) and Santee Cooper. These interconnections allow utilities to work together to provide an additional level of reliability. The strength of the system is also reinforced through coordination with other electric service providers in the Virginia-Carolinas (VACAR) sub-region, SERC Reliability Corporation (SERC) (formerly Southeastern Electric Reliability Council) and North American Electric Reliability Corporation (NERC).

The map on the following page provides a high-level view of the DEC service area.

- Peaking/Intermediate – 166 MW 4 x LM6000 Combustion Turbines
- Peaking/Intermediate – 201 MW 12 x Reciprocating Engine Plant
- Peaking/Intermediate – 870 MW 4 x 7FA.05 Combustion Turbines
- Renewable – 2 MW / 8 MWh Li-ion Battery
- Renewable – 5 MW Landfill gas

Non-Dispatchable

- Renewable – 150 MW Wind - On-Shore
- Renewable – 5 MW Solar PV

DEC - Assumptions of Load, Capacity, and Reserves Table

The following notes are numbered to match the line numbers on the Winter Projections of Load, Capacity, and Reserves tables. All values are MW (winter ratings) except where shown as a Percent.

1. Planning is done for the peak demand for the Duke Energy Carolinas System including Nantahala.

   A firm wholesale backstand agreement for 47 MW between Duke Energy Carolinas and Piedmont Municipal Power Agency (PMPA) starts on 1/1/2014 and continues through the end of 2020. This backstand is included in Line 1.

2. No additional firm sales are included.

3. Cumulative new energy efficiency and conservation programs (does not include demand response programs).

4. Peak load adjusted for firm sales and cumulative energy efficiency.

5. Existing generating capacity reflecting designated additions, planned uprates, retirements and derates as of January 1, 2016.

   Includes 101 MW Nantahala hydro capacity, and total capacity for Catawba Nuclear Station less 832 MW to account for North Carolina Municipal Power Agency #1 (NCMPA1) firm capacity sale.

6. Capacity Additions include:

   Includes runner upgrades on each of the four Bad Creek pumped storage units. Each upgrade is expected to be 46.4 MW and are projected in the 2021 – 2024 timeframe. One unit will be upgraded per year.

   Lee Combined Cycle is reflected in 2018 (683 MW). This is the DEC capacity net of 100 MW to be owned by NCEMC.

   Capacity Additions include Duke Energy Carolinas hydro units scheduled to be repaired and returned to service. The units are returned to service in the 2017-2020 timeframe and total 16 MW.

   Also included is a ~~91~~85 MW capacity increase due to nuclear uprates at Catawba and Oconee. Timing of these uprates is shown from 2017-2020.

Table 8-H DEC System Carbon Mass Cap Case Winter Resources by Fuel Type

DEC System Mass Cap Resources
Cumulative Winter Totals - 2017 - 2031

(Original)

Nuclear	2325
CC	1904
CT	700
Hydro	202
CHP	109
Solar	232
Total	5240

DEC System Mass Cap Resources
Cumulative Winter Totals - 2017 - 2031

(Revised)

Nuclear	2325
CC	1904
CT	468
Hydro	202
CHP	109
Solar	232
Total	5240

A detailed discussion of the assumptions, inputs and analytics used in the development of the System Mass Cap Case is contained in Appendix A. As previously noted, the further out in time planned additions or retirements are within the 2016 IRP, the greater the opportunity for input assumptions to change. Thus, resource allocation decisions at the end of the planning horizon have a greater possibility for change as compared to those earlier in the planning horizon.

Joint Planning Case

A Joint Planning Case that begins to explore the potential for DEC and DEP to share firm capacity between the Companies was also developed. The focus of this case is to illustrate the potential for the Utilities to collectively defer generation investment by utilizing each other's capacity when available and by jointly owning or purchasing new capacity additions. This case does not address the specific implementation methods or issues required to implement shared capacity. Rather, this case illustrates the benefits of joint planning between DEC and DEP with

Table 8-I DEC and DEP Joint Planning Case

(Original)

DEC and DEP Combined Resource Plan (1) Base Case - Winter				
Year	**Resource**		**MW**	
2017				
2018				
2019				
2020				
2021				
2022	New CC		1221	
2023	New CC	New CT	1221	468
2024				
2025	New CT		468	
2026				
2027	New Nuclear	New CT	1117	468
2028	New CT		468	
2029	New Nuclear	New CT	1117	468
2030				
2031	New CT		1404	

Notes: (1) Table only includes undesignated capacity additions.

Delay & Combine

Delay

Beyond Study Period

DEC and DEP Joint Planning Resource Plan (1) Base Case - Winter		
Year	**Resource**	**MW**
2017		
2018		
2019		
2020		
2021		
2022	New CC	1221
2023	New CC	1221
2024		
2025		
2026	New CT	936
2027	New Nuclear	1117
2028	New CT	468
2029	New Nuclear	1117
2030		
2031	New CT	1872

(Revised)

DEC and DEP Combined Resource Plan (1) Base Case - Winter				
Year	**Resource**		**MW**	
2017				
2018				
2019				
2020				
2021				
2022	New CC		1221	
2023	New CC	New CT	1221	468
2024				
2025	New CT		468	
2026	New CT		468	
2027	New Nuclear		1117	
2028	New CT		468	
2029	New Nuclear	New CT	1117	468
2030				
2031	New CT		1404	

Notes: (1) Table only includes undesignated capacity additions.

Delay & Combine

Delay

Delay & Combine

Beyond Study Period

DEC and DEP Joint Planning Resource Plan (1) Base Case - Winter		
Year	**Resource**	**MW**
2017		
2018		
2019		
2020		
2021		
2022	New CC	1221
2023	New CC	1221
2024		
2025		
2026	New CT	936
2027	New Nuclear	1117
2028	New CT	468
2029	New Nuclear	1117
2030		
2031	New CT	1872

A comparison of both the DEC and DEP Combined Base Case and Joint Planning Base Case by fuel type is represented below in Table 8-J.

<u>DEC Request for Proposal (RFP) Activity</u>

<u>Supply-Side</u>

No supply-side RFPs have been issued since the filing of DEC's 2015 IRP.

<u>Renewable Energy</u>

Duke Energy Distributed Energy Resource Solar RFP – South Carolina

A Shared Solar Program RFP was released on August 20, 2015, to solicit for up to 5 MW_{AC} (4 MW_{AC} in DEC/1 MW_{AC} in DEP) of solar PV facilities that would provide power and associated energy certificates within the DEC and DEP service territories in the state of South Carolina. Executed contracts in response to this RFP will be utilized to comply with the Duke Energy's "Shared Solar Program" under the South Carolina Distributed Energy Resource Program Act.

The RFP's interest was in solar PPAs and turnkey asset purchase proposals with a nameplate capacity sized > 250 kilowatts ($kW_{AC)}$ but no greater than 1 MW_{AC}. Proposals must be directly connected to the DEC or DEP transmission or distribution system in South Carolina. Projects must be in-service and capable of delivering fully rated output by December 31, 2016. PPA contract durations shall be a 10 year term.

Respondents were notified, February 22, 2016 of their proposal status and if they had been selected as a proposal of interest.

Proposals of interest were allowed to refresh bid pricing following the completion of DEC/DEP estimated interconnection costs. Proposals of interest are currently in varying stages of negotiations and contract execution.

Duke Energy Carolinas – General Compliance RFP

Under this RFP, DEC will be soliciting proposals to procure renewable resources to meet the general compliance under the ~~NC~~ North Carolina Renewable Energy and Energy Efficiency Portfolio Standard (REPS) while expanding DEC's emission free, diversified distributed generation portfolio. This RFP will seek up to 750,000 megawatt-hours (MWh) of energy and associated renewable energy certificates for projects that will achieve commercial operation within the 2017/2018 timeframe. Proposal structures allowed must be in the form of Purchased Power Agreements or Engineering, Procurement & Construction/Turnkey projects. All projects must be located in DEC's retail service territory~~. There will be a preference for growth and for new construction risk to be shared among the parties. This results in positive benefits for the Company's customers. The benefits of co-ownership of the Lee Nuclear Station with DEP were also illustrated with the ability to jointly plan as represented in the Joint Planning Case in this IRP.~~ in the state of North Carolina. There will be a preference for operational projects or projects in late stage of development.

Table A-2 DEC Cumulative Solar Summary (Nameplate MWs)

Year	Portfolio #1	Portfolio #2	Portfolio #3	Portfolio #4	Portfolio #5	Portfolio #6
2017	735	805	735	735	735	805
2018	907	1,057	907	907	907	1,057
2019	1,088	1,249	1,088	1,088	1,088	1,249
2020	1,244	1,436	1,244	1,244	1,244	1,436
2021	1,416	1,609	1,416	1,416	1,416	1,609
2022	1,542	1,810	1,542	1,542	1,542	1,810
2023	1,641	1,990	1,641	1,641	1,641	1,990
2024	1,724	2,140	1,724	1,724	1,724	2,140
2025	1,801	2,281	1,801	1,801	1,801	2,281
2026	1,873	2,413	1,873	1,873	1,873	2,413
2027	1,941	2,537	1,941	1,941	1,941	2,537
2028	2,004	2,654	2,004	2,004	2,004	2,654
2029	2,063	2,763	2,063	2,063	2,063	2,763
2030	2,118	2,864	2,118	2,118	2,618	2,864
2031	2,168	2,957	2,168	2,168	3,168	2,957

4. Perform Portfolio Analysis

The six portfolios identified in the screening analysis were evaluated in more detail with an hourly production cost model called PROSYM under several scenarios. The four scenarios are summarized in Table A-3 and included sensitivities on fuel, carbon, and capital cost.

Table A-3 Scenarios for Portfolio Analysis

	Carbon Tax/No Carbon Tax Scenarios[1]	Fuel	CO2	CAPEX
1	Current Trends	Base	CO2 Tax	Base
2	Economic Recession	Low Fuel	No CO2 Tax	Low
3	Economic Expansion	High Fuel	CO2 Tax	High

[1]Run Portfolios 1 - 4 through each of these 3 scenarios

	System Mass Cap Scenarios[2]	Fuel	CO2	CAPEX
4	Current Trends - CO_2 Mass Cap	Base	Mass Cap	Base

[2]Run Portfolios 5 - 6 through this single MC2 scenario

Portfolios 1 through 4 were analyzed under a current economic trend scenario (Scenario #1), an economic recession scenario (Scenario #2), and an economic expansion scenario (Scenario #3). Portfolios 5 & 6 were only evaluated under the Current Trends – CO_2 Mass Cap scenario (Scenario #4).

Under a System Mass Cap for carbon, fuel price and capital cost will have little impact on the optimization of the system as the carbon output of the various generators will control dispatch to a greater extent than the fuel price.

Portfolio 1 – 4 Analysis

Table A-4 below summarizes the PVRR of each portfolio compared to Portfolio #41 over the range of scenarios and sensitivities.

Table A-4 Delta PVRR for Portfolios #1 - #4 under Scenarios #1-#3

Delta PVRR 2016 - 2061, $Billions compared to Portfolio #1

Portfolio	Scenario #1 (Current Trends)	Scenario #2 (Economic Recession)	Scenario #3 (Economic Expansion)
Portfolio #1 (Base Case)	$0	$0	$0
Portfolio #2 (High Renew)	$322	$464	$430
Portfolio #3 (High EE)	$69	$335	$22
Portfolio #4 (High CC)	-$4,992	-$6,077	-$6,212

*Note: Positive values indicate Portfolio #41 is a lower cost, Negative values indicate Portfolio #41 is a higher cost.

Base Portfolio Load Impacts of DSM Programs

	Annual Peak MW Reduction					
Year	**IS**	**SG**	**PowerShare**	**PowerManager**	**EnergyWise for Business**	**Total Annual Peak**
2016	115	15	374	478	3	985
2017	109	15	380	502	9	1,015
2018	103	14	391	522	18	1,048
2019	98	13	401	540	27	1,079
2020	94	13	412	555	36	1,109
2021	89	12	416	555	45	1,117
2022	88	12	416	555	45	1,115
2023	88	12	416	555	45	1,115
2024	88	12	416	555	45	1,115
2025	88	12	416	555	45	1,115
2026	88	12	416	555	45	1,115
2027	88	12	416	555	45	1,115
2028	88	12	416	555	45	1,115
2029	88	12	416	555	45	1,115
2030	88	12	416	555	45	1,115
2031	88	12	416	555	45	1,115

Note: For DSM programs, Gross and Net are the same.

DEC's approved EE plan is consistent with the requirement set forth in the Cliffside Unit 6 CPCN Order to invest 1% of annual retail electricity revenues in EE and DSM programs, subject to the results of ongoing collaborative workshops and appropriate regulatory treatment.

However, pursuing EE and DSM initiatives is not expected to meet all of the future incremental peak demand for energy. DEC still envisions the need to secure additional generation, including cost-effective renewable generation, but the EE and DSM programs offered by DEC will address a significant portion of this need if such programs perform as expected.

EE Savings Variance since last IRP

In response to Order number 7 in the NCUC Order Approving Integrated Resource Plans and REPS Compliance Plans regarding the 2014 Biennial IRPs, the Base Portfolio EE savings forecast of MWh is within 10% of the forecast presented in the 2014 IRP when compared on the cumulative achievements at year ~~2033~~2031 of the forecasts as shown in the table below.

Duke Energy is exploring and working with potential customers with good base thermal loads on a regulated Combined Heat and Power offer. The CHP asset will be included as part of Duke Energy's IRP as a placeholder for future projects as described below. The steam sales are credited back to the revenue requirement of the projects to reduce the total cost of this generation grid resource, making this a low cost grid asset. Along with the potential to be a competitive cost generation resource, CHP can result in CO_2 emission reductions, deferral of T&D expenses, and present economic development opportunities for the state.

Duke Energy has publically announced its first CHP project, a 20 MW investment at Duke University. We are currently working with other industrial, military and Universities for future project expansions.

- **Addition of Battery Storage to the IRP**

Energy storage solutions are becoming an ever growing necessity in support of grid stability at peak demand times and in support of energy shifting and smoothing from renewable sources. Energy Storage in the form ~~or~~of battery storage is becoming more feasible with the advances in battery technology (Tesla low-cost Lithium-ion battery technology) and the reduction in battery cost; however, their uses (even within Duke Energy) have been concentrated on frequency regulation, solar smoothing, and/or energy shifting from localized renewable energy sources with a high incidence of intermittency (i.e. solar and wind applications).

Duke Energy has several projects in operation since 2011, mainly in support of regulating output voltages/frequencies from renewable energy sources to the grid. This includes projects as large as the Notrees Battery Storage project (36 MW) which supports a wind farm down to the smaller 250 kW Marshall Battery Storage Project which supports a 1.2 MW solar array. Additional examples include the Rankin Battery Storage Project (402 kW), the McAlpine Community Energy Storage Project (24 kW), McAlpine Substation Energy Storage Project (200 kW), and a 2 MW facility on Ohio's former Beckjord Station grounds. Each of these applications supports frequency regulation, solar smoothing, or energy shifting from a local solar array. These examples are only a few in support of a growing trend of coupling Battery Storage with an intermittent renewable energy source such as solar or wind in an effort to stabilize output and increase a facility's (renewable plus storage) net capacity factor.

Dispatchable (Summer Ratings)

- Base load – 782 MW Ultra-Supercritical Pulverized Coal with CCS
- Base load – 557 MW 2x1 IGCC with CCS
- Base load – 2 x 1,117 MW Nuclear Units (AP1000)
- Base load – 576 MW – 1x1x1 Advanced Combined Cycle (Inlet Chiller and Fired)
- Base load – 1,160 MW – 2x2x1 Advanced Combined Cycle (Inlet Chiller and Fired)
- Base load – 20 MW – Combined Heat & Power
- Peaking/Intermediate – 166 MW 4 x LM6000 Combustion Turbines
- Peaking/Intermediate – 201 MW 12 x Reciprocating Engine Plant
- Peaking/Intermediate – 870 MW 4 x 7FA.05 Combustion Turbines
- Renewable – 2 MW / 8 MWh Li-ion Battery
- Renewable – 5 MW Landfill gas

Non-Dispatchable

- Renewable – 150 MW Wind - On-Shore
- Renewable – 5 MW Solar PV
- ~~Renewable – 2 MW / 8 MWh Li-ion Battery~~

Information Sources

The cost and performance data for each technology being screened is based on research and information from several sources. These sources include, but may not be limited to the following internal Departments: Duke Energy's Project Management & Construction, Emerging Technologies, and Generation & Regulatory Strategy. The following external sources may also be utilized: proprietary third-party engineering studies, the Electric Power Research Institute Technical Assessment Guide (TAG®), and Energy Information Administration (EIA). In addition, fuel and operating cost estimates are developed internally by Duke Energy, or from other sources such as those mentioned above, or a combination of the two. EPRI information or other information or estimates from external studies are not site-specific, but generally reflect the costs and operating parameters for installation in the Carolinas. Finally, every effort is made to ensure that capital, O&M costs, fuel costs and other parameters are current and include similar scope across the technologies being screened. The supply-side screening analysis uses the same fuel prices for coal and natural gas, and nitrogen oxides ($NO_{x)}$), sulfur dioxide ($SO_{2)}$), and CO_2 allowance prices as those utilized downstream in the detailed analysis (discussed in Appendix A). Screening curves were developed for each technology to show the economics with and without carbon costs (i.e. No Carbon Tax, Carbon Tax, System Carbon Mass Cap).